UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket Nos. ____________ RM06-16-000**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-004-3

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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-004-3 (Protection System Misoperation Identification and Correction) (Exhibit A). 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.[4] NERC also requests approval of: (i) a revised definition of "Misoperation" and a new definition of "Composite Protection System" for inclusion in the NERC Glossary of Terms; (ii) the Implementation Plan for the proposed Reliability Standard (Exhibit B); (iii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and F); and (iv) the retirement of Reliability Standards PRC-004-2.1a (Analysis and Mitigation

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

of Transmission and Generation Protection System Misoperations) and PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System) as listed in the Implementation Plan.[5]

As required by Section 39.5(a)[6] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard PRC-004-3, a summary of the development history (Exhibit G), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (Exhibit D). The NERC Board of Trustees adopted proposed Reliability Standard PRC-004-3 on August 14, 2014.

I. EXECUTIVE SUMMARY

Reducing the risk to reliability from Protection System misoperations will require consistent collection of Misoperation information along with systematic analysis and correction of the underlying causes of preventable Misoperations. Proposed PRC-004-3 and the separate Request for Data or Information prepared pursuant to Section 1600 of NERC's Rules of Procedure ("Misoperations Data Request"), provide the means to accomplish this systematic analysis and correction. Proposed Reliability Standard PRC-004-3 replaces Reliability Standards PRC-004-2.1a and PRC-003-1 to create a single Reliability Standard requiring Transmission Owners, Generator Owners, and Distribution Providers to identify and correct causes of Misoperations of certain Protection Systems for Bulk Electric System Elements. Proposed Reliability Standard PRC-004-3 requires the applicable entities to review Protection System

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5 PRC-003-1 is not a Commission-approved NERC Reliability Standard. *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 Fed. Reg. 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1460-61 (2007) (neither approving nor remanding PRC-003-1).

6 18 C.F.R. § 39.5(a) (2014).

7 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).

operations to identify Misoperations, including those where there is a shared responsibility for the review, and correct the causes of Misoperations to avoid reoccurrence. In developing PRC-004-3, NERC has addressed outstanding Commission concerns and directives related to PRC-004-2.1a and PRC-003-1 as well as made other improvements to the standard. For the reasons discussed in this Petition, NERC respectfully requests that the Commission approve the proposed Reliability Standard PRC-004-3, including its associated new and revised defined terms, as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[8]

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III. BACKGROUND

A. Regulatory Framework

[8] 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 (2014), to allow the inclusion of more than two persons on the service list in this proceeding.

By enacting the Energy Policy Act of 2005,[9] 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 Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[10] 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)[11] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[12] 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[13] and Section 39.5(c)[14] 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

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9 16 U.S.C. § 824o (2012).
10 *Id.* § 824(b)(1).
11 *Id.* § 824o(d)(5).
12 18 C.F.R. § 39.5(a).
13 16 U.S.C. § 824o(d)(2).
14 18 C.F.R. § 39.5(c)(1).

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[15] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[16] 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[17] and thus satisfies certain of the criteria for approving Reliability Standards.[18] 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 stakeholders must approve, and the NERC Board of Trustees must adopt a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

C. History of PRC-004 and PRC-003

PRC-003 requires the Regional Reliability Organizations to establish, document and maintain regional procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations, and PRC-004 requires entities to analyze their

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15 *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.").

16 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.

17 116 FERC ¶ 61,062 at P 250.

18 Order No. 672 at PP 268, 270.

Protection System Misoperations and develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the regional procedures.

In Order No. 693, the Commission approved PRC-004-1 as mandatory and enforceable.[19] The Commission also stated that PRC-004 "serves an important purpose in ensuring that transmission and generation protection system misoperations affecting the reliability of the Bulk-Power System are analyzed and mitigated."[20] In the *Notice of Proposed Rulemaking* preceding Order No. 693, the Commission stated that it did not identify any substantive issues with the Reliability Standard.[21] Since the approval of version 1 of PRC-004, the Commission has also approved other minor changes to the Reliability Standard and an interpretation.[22]

In Order No. 693, the Commission identified PRC-003-1 as a "fill-in-the-blank"[23] standard because the standard included references to regional procedures that had not been submitted by NERC.[24] As a result, the Commission decided to not approve or remand PRC-003-1 until NERC submitted the additional information. Since PRC-003-1 is not mandatory and

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19 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 1467 (2007).

20 *Mandatory Reliability Standards for the Bulk-Power System*, Notice of Proposed Rulemaking, 117 FERC ¶ 61,084 at P 839 (2006) ("Order No. 693 NOPR").

21 Order No. 693 NOPR, 117 FERC ¶ 61,084 at P 834.

22 *See Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 (2012) (approving PRC-004-2.1a and clarifying that the requirements in PRC-004 extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facilities); *N. Am. Elec. Reliability Corp.*, 134 FERC ¶ 61,015 (2011) (approving PRC-004-2, which included modifications in response to Order No. 693 P 1469); *N. Am. Elec. Reliability Corp.*, 136 FERC ¶ 61,208 (2011) (approving an interpretation for the term "transmission Protection System" as it appears in Requirements R1 and R3).

23 In Order No. 693, certain Reliability Standards were classified as "fill-in-the-blank" standards because they contained provisions that required the regional reliability organizations to develop criteria for use by users, owners or operators within each region. Order No. 693 at PP 287-88, 297.

24 Order No. 693 at PP 1458, 1460.

enforceable, there is not a Commission-approved standard for Regional procedures to support the requirements of PRC-004.[25]

D. History of Project 2010-05.1 Protection System (Misoperations)

When the original scope for the NERC System Protection and Control Task Force (now the System Protection and Control Subcommittee "SPCS") was developed, one of the assigned items was to review all of the existing PRC-series of Reliability Standards, to advise the NERC Planning Committee on their status, and to develop Standards Authorization Requests ("SARs"), as appropriate, to address any perceived deficiencies.[26] In May of 2009, the SPCS released an assessment of Reliability Standards PRC-003-1, PRC-004-1, and PRC-016-1. The assessment acted as a precursor for a SAR to be submitted by the SPCS that would recommend revision of the definition of Misoperation, modification of PRC-003, PRC-004, and PRC-012, and retirement of PRC-016. The approach in proposed PRC-004-3 and the separate data request prepared by NERC is consistent with the reliability objectives in the SPCS report. NERC has modified PRC-004 and proposed to retire PRC-003, opting instead to reflect the objectives in PRC-003 in the PRC-004 revisions. The second phase of the Project, as described below, will address the SPS/RAS aspects of the SPCS report including changes to PRC-012 and PRC-016.

Project 2010-05 – Protection Systems was established to improve monitoring of Bulk Electric System Protection System events, as well as identify and correct the causes of Misoperations to improve Protection System performance. In 2011, the work in the Project 2010-05was subdivided into two phases, Project 2010-05.1 and Project 2010-05.2, in order to address the work associated with Misoperations of Protection Systems ahead of the work

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[25] Although PRC-003-1 is not FERC-approved, NERC still uses the standard to support efforts related to PRC-004-2.

[26] *NERC SPCS Assessment of Standards*, System Protection and Control Subcommittee at ii (May 22, 2009).

associated with Special Protection Systems and Remedial Action Schemes.[27] Phase I - Project 2010-05.1 Protection System (Misoperations), which is the subject of this Petition, includes the modification of the definition of "Misoperation", modification of PRC-004-2.1a, and the retirement of both PRC-004-2.1a and PRC-003-1.[28,29]

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit D and below, the proposed Reliability Standard PRC-004-3 and associated new and revised definitions, satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section provides background information from NERC's *State of Reliability* 2014 report[30] on NERC's analysis of misoperations. It also explains the purpose of PRC-004-3, provides a description of and the technical basis for the requirements, and describes how the proposed Reliability Standard and associated definitions improve reliability as compared to prior versions. This section also provides a brief summary of how the proposed Reliability Standards satisfy the outstanding Commission directives from Order No. 693 related to PRC-004 and PRC-003. Finally, this section includes a discussion of the enforceability of the proposed Reliability Standard.

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27 *See* NERC Standards Committee Meeting Minutes (Jun. 9, 2011), available at http://www.nerc.com/docs/standards/sc/sc_060911m_package.pdf.

28 The standard development page for Project 2010-05.1 is available here: http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx.

29 Phase II, Project 2010-05.2 Special Protection Systems is addressing all aspects of Special Protection Systems and Remedial Action Schemes including Misoperations of Special Protection Systems. Project 2010-05.2 will consider retirement of or modifications to Reliability Standards PRC-012-0 (Special Protection System Review Procedure), PRC-013-0 (Special Protection System Database), PRC-014-0 (Special Protection System Assessment), PRC-015-0 (Special Protection System data and Documentation), PRC-016-0.1 (Special Protection System Misoperations), and PRC-017-0 (Special Protection System Maintenance and Testing). The standard development page for Project 2010-05.2 is available here: http://www.nerc.com/pa/Stand/Pages/Project-2010-05_2–Special-Protection-Systems.aspx.

30 *State of Reliability 2014*, NERC (May 2014), *available at* http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf.

A. Misoperations

Nearly all major system failures, excluding those caused by severe weather, include Misoperations as a factor contributing to the propagation of the events. As noted in the *State of Reliability 2014* report, Bulk-Power System reliability and performance remains high; however, Protection System Misoperation was identified as having a significant probability of occurrence and is positively correlated with transmission severity when outages do occur.[31] The report made three additional findings from analyses of misoperations from 2011 through 2013:

- Misoperation occurrences have been consistent over the past three years, with approximately 2,000 misoperations per year.
- The rate of misoperations, as a percentage of total operations, has remained consistent during this period at approximately 10 percent (i.e., roughly one in 10 operations is a misoperation).
- The three most common causes of misoperations remain the same (approximately 65 percent of misoperations are caused by settings/logic/design errors, communication failures, and relay failures).[32]

The report concluded that understanding and reducing misoperations should remain a focus of NERC and industry participants. The report recommends completion of the development of proposed Reliability Standard PRC-004-3 as a means to address the reliability risks posed by misoperations.[33] Reducing the risk to reliability from Protection System misoperations will require consistent collection of Misoperation information along with systematic analysis and correction of the underlying causes of preventable Misoperations. Proposed PRC-004-3, and the parallel Section 1600 Data Request provide means to accomplish this systematic analysis and correction.

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[31] One dataset used to assess risk associated with misoperations is the data collected by the Regions and NERC through periodic reporting pursuant to PRC-004-2.1a.

[32] *State of Reliability 2014* at 16.

[33] Other NERC activities aimed at reducing misoperations are detailed in the *State of Reliability 2014* report.

B. Proposed Reliability Standard PRC-004-3

1. Purpose and Applicability of PRC-004-3

Proposed Reliability Standard PRC-004-3 revises the currently effective PRC-004-2.1a Reliability Standard. PRC-004-2.1a ensures that all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System are analyzed and mitigated. Similarly, the purpose of the proposed Reliability Standard is to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System Elements. The proposed standard also takes into account the reliability objective of PRC-003-1, which is to establish, document and maintain regional procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. PRC-004-3 eliminates the need for regional procedures by providing continent-wide parameters for investigating Protection System operations and identifying Misoperations. Proposed PRC-004-3 applies to Transmission Owners, Generator Owners, and Distribution Providers. It also applies to underfrequency load shedding that is intended to trip one or more Bulk Electric System Elements. Underfrequency load shedding was added to PRC-004-3 to close a gap in reliability as Misoperations of these relays are not currently covered by a Reliability Standard.[34] The standard further specifies that the requirements apply to Protection Systems for Bulk Electric System Elements, with four exclusions as described below.

During development of the proposed standard, the standard drafting team determined that specific exclusions were needed to provide clarity on what facilities are included within the

[34] Undervoltage load shedding has not been included in the proposed Reliability Standard because Misoperations of undervoltage load shedding relays are currently addressed by Requirement R1 of Reliability Standard PRC-022-1 (Under-Voltage Load Shedding Program Performance). *See* PRC-022-1, *available at* http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-022-1&title=Under-Voltage Load Shedding Program Performance&jurisdiction=United States.

scope of proposed PRC-004-3. The exclusions do not change the applicability of the standard; rather, they clarify the existing applicability and provide certainty to entities regarding the facilities subject to the standard. First, BES interrupting device operations initiated by non-protective functions are not Protection System operations. Because the definition of Misoperation, as described more fully below, is tailored to cover "the failure of a Composite Protection System to operate as intended *for protection purposes*"[35] (emphasis added), these operations initiated by non-protective functions would not fall within the scope of the standard. Second, the standard drafting team included an explicit exclusion in Section 4.2.1.1 of the Applicability of the proposed standard for "[n]on-protective functions that are embedded within a Protection System." The standard drafting team also recognized that entities use Protection Systems as part of a routine practice to control BES Elements. As a result, the standard drafting team in Section 4.1.1.2 excluded "[p]rotective functions intended to operate as a control function during switching." Finally, the standard drafting team separately excluded Special Protection Systems and Remedial Action Schemes. Misoperations of Special Protection Systems and Remedial Action Schemes are currently addressed in Reliability Standard PRC-016-0.1. Requirements related to Special Protection Systems and Remedial Action Schemes, as noted above, will be addressed in the second phase of this Project.

2. Proposed Defined Terms and Requirements

a) Proposed Defined Terms

In order to improve the clarity of the definition of Misoperation and the coverage of Protection Systems in the requirements, two new or revised defined terms were developed by the

[35] *See infra* proposed definition of Misoperation in Section IV.B.2.a.

standard drafting team and are proposed for use with the requirements in PRC-004-3. The proposed defined terms and an explanation of each are included below.

(1) Definition of Composite Protection System

A new defined term, "Composite Protection System" has been introduced in the proposed standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation of that Element's Protection System. The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. Five examples of a Composite Protection System are included in the proposed PRC-004-3 Application Guidelines.

(2) Definition of Misoperation

The standard drafting team determined that the existing definition of Misoperation lacked sufficient clarity and specificity to achieve consistent application on a continent-wide basis. The current definition reads:

> • Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
>
> • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
>
> • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

For example, the terms "specified time" and "abnormal condition" used in the existing definition are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation. The proposed definition resolves these issues by simplifying the definition to be any failure of a Composite Protection System to operate as intended for protection purposes and provides six categories of Misoperation. The revised definition improves the use of "specified time" by describing a slow trip as a duration that results in the operation of at least one other Element's Composite Protection System in the two categories for a slow trip of a Protection System (Slow Trip – During Fault and Slow Trip – Other Than Fault). The revised definition removes the ambiguity of "abnormal condition" by using the phrase "for a non-Fault condition, and specifically for the failure to trip category, by using the phrase "to operate for a non-Fault condition for which it is designed." The definition of "Misoperation" is further enhanced by incorporating the new proposed term "Composite Protection System" within the definition. The use of Composite Protection System indicates that a single component failure does not constitute a Misoperation if the overall (composite) Protection System operates as intended. Without the reference to Composite Protection System, applicable entities have been left to make a determination as to whether a single component failure would qualify the Protection System operation as a Misoperation and, therefore, has led to inconsistent identification and reporting.

The proposed definition of Misoperation provides additional clarity over the current version. It is based on the principle that an Element's total complement of protection is intended to operate dependably and securely. For example, the Failure to Trip and Slow Trip categories are associated with Protection System dependability, while the Unnecessary Trip categories are associated with Protection System security. The definition includes six categories, as noted below, which provide further differentiation within the definition of what constitutes a Misoperation. The proposed PRC-004-3 Application Guidelines contain additional detail on these categories. The proposed definition reads:

Misoperation: The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. Failure to Trip – During Fault – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. Failure to Trip – Other Than Fault – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. Slow Trip – During Fault – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. Slow Trip – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. Unnecessary Trip – During Fault – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. Unnecessary Trip – Other Than Fault – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

b) Proposed Requirements

In designing the Requirements[36] in proposed PRC-004-3, the standard drafting team used three objectives as identified in the SAR as a drafting guide to ensure key elements were included in the proposed standard. First, the standard must include the review of all Protection System operations on the Bulk Electric System in order to identify those operations that classify as Misoperations of Protection Systems for Facilities that are part of the Bulk Electric System.[37] Second, the standard must require entities to analyze Misoperations of Protection Systems for Facilities that are part of the Bulk Electric System to identify the cause(s). Third, the standard must require entities to develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the Bulk Electric System.

(1) Requirement R1

> ***R1.*** *Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*
>
> > ***1.1*** *The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and*
> >
> > ***1.2*** *The BES interrupting device owner owns all or part of the Composite Protection System; and*
> >
> > ***1.3*** *The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.*

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36 A graphical representation demonstrating the relationships between Requirements developed by the standard drafting team can be found on page 42 of proposed PRC-004-3 in the Application Guidelines.

37 NERC will address Misoperations associated with Special Protection Systems and Remedial Action Schemes in the second phase of this project.

Requirement R1 requires a review of each BES interrupting device[38] operation meeting the circumstances in Parts 1.1, 1.2, and 1.3 to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner monitors and tracks device operations, the owner is the logical entity to initiate the process of identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or the operation was caused by manual intervention in response to its Protection System failure to operate.

The applicable entity in Requirement R1 has 120 calendar days[39] to identify whether a BES interrupting device operation was initiated by a Protection System Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary. While identifying the cause is implicit in the structure of the proposed standard, it is necessary to identify the cause in order to determine whether an entity is responsible for performance under other Requirements.

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[38] A BES interrupting device is a BES Element, e.g. a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation. *See* PRC-004-3, Application Guidelines at 23.

[39] The time period within each Requirement is distinct and separate from the time periods listed in other Requirements.

(2) Requirement R2

R2. *Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

> ***2.1*** *For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:*
>
> > ***2.1.1*** *The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and*
> >
> > ***2.1.2*** *The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and*
> >
> > ***2.1.3*** *The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.*
>
> ***2.2*** *For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.*

Requirement R2 ensures notification occurs to those who must play a role in identifying Misoperations for an applicable BES interrupting device operation. Notification is not accounted for within Requirement R1 to limit each requirement to a single performance category in each requirement. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to identify those Protection System operations meeting the circumstances in Parts 2.1.1, 2.1.2, and 2.1.3; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 are met. Requirement R2 does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. Notification is required when the circumstances in Parts 2.1.1, 2.1.2, and 2.1.3 are met, thus avoiding unnecessary notifications and redirecting of resources by the recipient. The applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2.

Part 2.2 is applicable when a BES interrupting device fails to operate due to a Protection System failure and results in operation of a Protection System intended to operate as backup protection for a condition on another entity's BES Element. In this case, the entity that provided backup protection, upon identifying operation of its Protection System providing backup protection for a condition on another entity's BES Element, must provide notification of the operation to the other. The applicable entity receiving the notification must initiate a review of its Protection System under Requirement R3.

Of particular note, a Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

(3) Requirement R3

> ***R3.*** *Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as operation counters, relay targets, supervisory control and data acquisition (SCADA), Disturbance Monitoring Equipment (DME), and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The entity that is notified by the BES interrupting device owner is allowed until the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its Protection System components caused a Misoperation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the "60 calendar days" only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1. This setup assures that entities will, at a minimum, have 60 calendar days to determine if its Protection System components caused a Misoperation.

(4) Requirement R4

> ***R4.*** *Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: [Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*
>
> - *The identification of the cause(s) of the Misoperation; or*
> - *A declaration that no cause was identified.*

Requirement R4 requires the entity that owns the BES interrupting device or an entity that was notified to take investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The standard drafting team included this Requirement because there will be cases where the cause(s) of a Misoperation will not be revealed during the review for Misoperation in Requirements R1 or R3. Requirement R4 provides a mechanism to continue the investigative work to determine the cause(s) of an identified Misoperation when the cause is not known. At least one investigative action must be performed every two full calendar quarters until the investigation is completed. This time period was allocated in recognition of the time needed to schedule and complete certain planned investigative actions. The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined.

(5) Requirement R5

> ***R5.*** *Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]*

• Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or

• Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. A formal Corrective Action Plan ("CAP") is a proven tool for resolving and reducing the possibility of recurrence of operational problems. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s), within 60 calendar days of first determining a cause, to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The 60 calendar day period for developing a CAP (or declaration) is established based on industry experience, which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule. The development of a CAP is intended to document the specific corrective actions needed to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations of other Protection Systems. The PRC-004-3 Application Guidelines contain examples of CAPs and other declarations to assist applicable entities.

(6) Requirement R6

R6. *Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. [Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetables change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the Bulk-Power System.

3. Improvements Reflected in Proposed PRC-004-3

Proposed PRC-004-3 and its associated new and revised definitions improve upon the currently effective Reliability Standard and the current method of collecting Misoperation data. First, the proposed standard takes the three reliability activities co-mingled in the Requirements of PRC-004-2.1a and separates them into individual Requirements. Second, the Requirements now also include additional specificity for notifying other owners and requiring other owners that receive notification to review its Protection System components for Misoperations. Third, the revised definition of Misoperation and the revised Applicability section of proposed PRC-004-3 provide necessary clarity regarding the components, conditions, and categories that are within scope of the review for Misoperations. Fourth, as noted below in NERC's response to the Commission's directives, the results-based Requirements in proposed PRC-004-3 require performance based on uniform, continent-wide criteria for the analysis of Protection System operations through Requirements R1, R2, R3, and R4 and mitigation of identified Misoperations (Requirements R5 and R6). As a result, NERC is able to streamline the body of Reliability Standards and eliminate PRC-003-1, allowing NERC to increase uniformity in the approach to addressing Misoperations. Finally, moving the periodic reporting of Misoperations from the standard and into a separate data request pursuant to Section 1600 of NERC's Rules of Procedure will permit NERC's data analysis to continue separately from compliance with the standard and continue reporting, using a standardized template, for all entities subject to the data request. All of these improvements will result in improved and more consistent review, reporting, and analysis of Protection System operations for Misoperation.

C. Consideration of the Commission's Directives

In Order No. 693, the Commission issued directives related to both PRC-004-3 and PRC-003-1, leaving unresolved issues for NERC to address. With respect to PRC-003-1, the Commission did not approve or remand PRC-003-1, instead choosing to wait to act until NERC submitted additional information.[40] As explained in the Tables of Issues and Directives (Exhibit E) and the Mapping Document (Exhibit C), PRC-003-1 will be retired by proposed PRC-004-3. The results-based Requirements in proposed PRC-004-3 require performance based on uniform, continent-wide criteria for the analysis of Protection System operations through Requirements R1, R2, R3, and R4 and mitigation of identified Misoperations (Requirements R5 and R6). Thus, it is not necessary to maintain a separate standard for process alone. Therefore, NERC will not submit the additional information needed to obtain Commission action to approve PRC-003-1. The standard drafting team has considered the additional directive from Order No. 693 related to PRC-003-1 in its construction of PRC-004-3. In P 1461, the Commission directed NERC to consider whether greater consistency can be achieved. This is achieved, as noted above, through the uniform, continent-wide criteria for analyzing Protection System operations and identifying Misoperations and by maintaining the reporting requirements for periodic

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[40] Order No. 693 at P 1460.

Misoperations based on a continent-wide template. All reporting of Misoperations will be done through the separate Misoperations Data Request instead of having PRC-004-3 specify an administrative reporting requirement as a compliance element. The Misoperations Data Request has been included for informational purposes as Exhibit H.

With respect to PRC-004, the Commission directed NERC in Order No. 693 to "consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1."[41] The standard drafting team took ISO-NE's comments under advisement and determined that the proper functional entities to include in the applicability are the Transmission Owner, Generator Owner, and Distribution Provider who own the BES Protection Systems. Owners of Protection Systems have personnel with subject matter expertise, Protection System design and setting information, and disturbance monitoring data, necessary to identify whether Protection System components cause a Misoperation, identify causes, and develop and implement CAPs. As owners of Protection Systems, the Transmission Owner, Generator Owner, and Distribution Provider have the responsibility to assure proper operation and implement corrective actions as needed. It therefore would be inappropriate to assign responsibility to entities that do not own Protection Systems, such as Load Serving Entities and Transmission Operators.

D. Enforceability of Proposed Reliability Standards

The proposed Reliability Standard PRC-004-3 includes Measures that support each requirement to help ensure that the requirements will be enforced in a clear, consistent, non-preferential manner and without prejudice to any party. The proposed Reliability Standard also includes VRFs and VSLs for each requirement. The VRFs and VSLs for the proposed

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[41] *Id.* at P 1469.

Reliability Standard comport with NERC and Commission guidelines related to their assignment. A detailed analysis of the assignment of VRFs and the VSLs for proposed PRC-004-3 is included as Exhibit F.

V. CONCLUSION

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 F); and
- the Implementation Plan, including the noted retirement, included in Exhibit B.

Respectfully submitted,

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Date: September 15, 2014

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 the RM06-16-000 proceeding.

Dated at Washington, D.C. this 15th day of September, 2014.

/s/ William H. Edwards

William H. Edwards
Counsel for North American Electric Reliability Corporation

Exhibit A

Proposed Reliability Standard PRC-004-3

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-3

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

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 for BES Elements, with the following exclusions:

   4.2.1.1 Non-protective functions that are embedded within a Protection System.

   4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

   4.2.1.3 Special Protection Systems (SPS).

   4.2.1.4 Remedial Action Schemes (RAS).

   4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

5. **Background**:

   A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap;

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information (“data request”). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation

2 http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

1a	February 17, 2011	Adopted by the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	August 14, 2014	Adopted by Board of Trustees	Revision under Project 2010-05.1

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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3 http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

4 "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

5 "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

6 "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker’s Composite Protection System. Considering breaker failure protection to be part of another Element’s Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the “Slow Trip” criteria of the Misoperation definition.

- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line’s Composite Protection System.
- An example of a correct operation of the breaker’s Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker’s Composite Protection System.
- An example of an “Unnecessary Trip – During Fault” is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault –** *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element’s Composite Protection System. If a generating unit’s Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an “Unnecessary Trip – During Fault” Misoperation of the generating unit’s Composite Protection System. This event would be a “Slow Trip – During Fault” Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

Example 4: A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity’s BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner’s differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little

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[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion.

In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

The following are examples of a declaration where no cause was determined:

Example R4b: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

Example R4c: A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

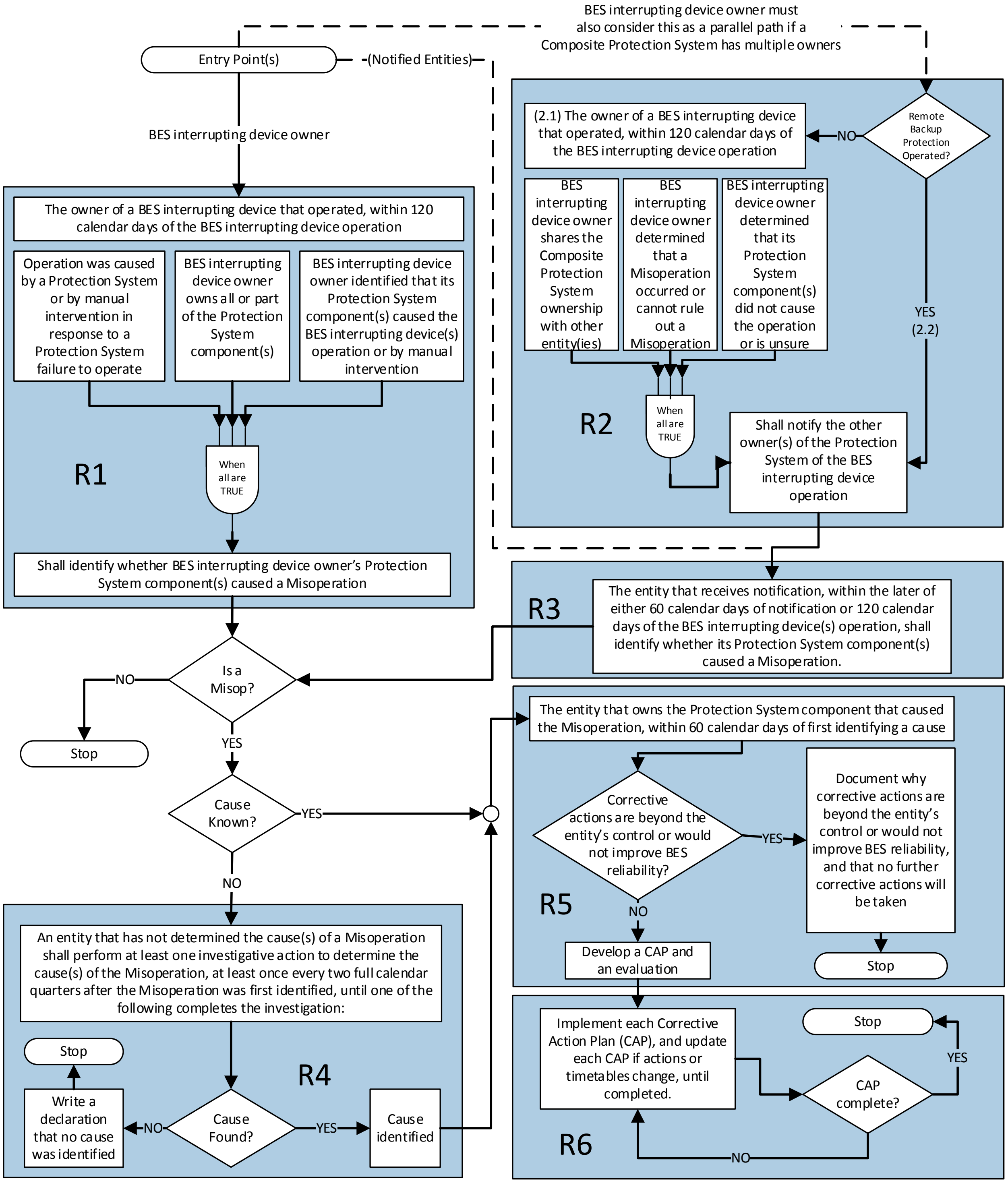
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



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 were moved to this section.

Rationale for Applicability:

Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

Rationale for R1:

This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

Rationale for R2:

Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

Rationale for R3:

When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

Rationale for R4:

If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

Rationale for R5:

A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

Rationale for R6:

Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

Exhibit B

Implementation Plan

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction
- Definitions of "Composite Protection System" and "Misoperation"

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage,

overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements, with the following exclusions:
    - Non-protective functions that are embedded within a Protection System.
    - Protective functions intended to operate as a control function during switching.
    - Special Protection Systems (SPS).
    - Remedial Action Schemes (RAS).
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

The standard, the revised definition of “Misoperation,” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of “Misoperation,” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months 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

The existing standards, PRC-003-1 and PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-3.

Exhibit C

Mapping Document

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the standard drafting team is recommending revisions to the standard, those changes are identified in the "Translation to PRC-004-3 or Other Action" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered entity functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based standard (RBS) construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also directs focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners that share a Misoperation identification responsibility of the Composite Protection System when it determines (or is unsure) its Protection System component(s) did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		continue its investigative work to determine the cause(s) of an identified Misoperation, if not determined in R1 or R3, until the cause(s) is determined or the entity declares that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**4.2.** Facilities: **4.2.1** Protection Systems for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded and will be addressed in phase two of this project and have been excluded in the Applicability.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	Protection System component(s) caused a Misoperation: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to a Protection System failure to operate.	ensuring that other owners had a responsibility to be involved in the review and analysis.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated	Requirement R2 asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and	the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation is identified (or cannot be ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	be provided to the other Protection System owner(s) for which that backup protection was provided.	identify a possible Misoperation under Requirement R3 by the other owner(s).
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	cause(s) of a Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of the applicable entities. As such, reporting to Regional Entities will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		remediation techniques; and publicize lessons learned for the industry. Metrics will be validated and shared with each Regional Entity. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	document in a declaration that a CAP is not practical. The entity must explain in a declaration why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection Systems for BES Elements without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard, revised definition of "Misoperation," and new definition of "Composite Protection System" provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity's (formerly Regional Reliability

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Organization or RRO) approval of procedures. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission	None.	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) to the applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.		little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS).	The same applicable entities will transition to the new PRC-004-3 standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	Remedial Action Schemes (RAS) are addressed in phase two of this project and have been excluded in the Applicability.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and	The currently approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3).

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	**1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to a Protection System failure to operate. **R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the	The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation is identified (or cannot be ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 by the other owner. Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar	in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review. Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause(s) of an identified Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those Protection Systems at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity must document in a declaration that a CAP actions are beyond the entity's control or would not improve BES reliability. The entity must explain in a declaration why no further action will be taken.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	None.	Since the NERC Rules of Procedure, Section 1600 Request for Data or Information will replace the reporting obligations, NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Exhibit D

Order No. 672 Criteria

Exhibit D
<u>Order No. 672 Criteria</u>

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]**

Proposed Reliability Standard PRC-004-3 achieves the specific reliability goal of identifying and correcting the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. Proposed Reliability Standard PRC-004-3 revises the currently effective PRC-004-2.1a Reliability Standard, which ensures that all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System are analyzed and mitigated. The proposed standard also takes into account the reliability objective of PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection

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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.

Systems), which is to establish, document and maintain regional procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. PRC-004-3 eliminates the need for regional procedures by providing continent-wide parameters for investigating Protection System operations and identifying Misoperations.

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 applies to Transmission Owners, Generator Owners, and Distribution Providers. It also applies to underfrequency load shedding that is intended to trip one or more Bulk Electric System Elements.. The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. For a complete description of each requirement and the language in each, please refer to Section IV.B.2.b of NERC's Petition. The proposed Reliability Standard separates each performance element required to identify and correct Misoperations into a separate requirement to improve clarity and remove the comingling of performance elements found in the requirements of PRC-004-2.1a. The proposed standard also includes clear timing elements, which are supported by detailed explanation in the application guidelines developed by the standard drafting team.

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]**

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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.

[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.

The Violation Risk Factor ("VRF") and Violation Severity Level ("VSL") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The assignment of the severity levels for the VSLs is consistent with the corresponding Requirement and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, and support uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences.

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 contains Measures that support the requirements by clearly identifying what is required and how the requirements will be measured for compliance. The Measures, contained in Section C of the proposed PRC-004-3 Reliability Standard are as follows:

> **M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.
>
> **M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3

[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.

and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

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 the reliability goal effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard continues to employ a similar process to identify and correct Misoperations of Protection Systems as that utilized in the currently effective Reliability Standard, thereby using the most efficient means to maintain the effective identification and correction of these occurrences. NERC has also moved the periodic reporting of Misoperations from the standard and into a separate data request pursuant to Section 1600 of NERC's Rules of Procedure. This will permit NERC's data analysis to continue separately from compliance with the standard and continue reporting, using a standardized template, for all entities subject to the data request. This separation promotes efficiency in implementing and monitoring compliance of the Reliability Standard by moving the reporting burden into NERC's data collection program rather than as part of the standard.

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

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[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.

[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.

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. This proposed Reliability Standard is the result of multiple industry ballots and revisions that reflect an active comment and response process between industry and the standard drafting team. The result of these efforts was a stronger final proposed Reliability Standard that protects the reliability of the Bulk-Power System. The standard also reflects direction and input through an assessment of NERC's System Protection and Control Subcommittee. Further, NERC's current data collection efforts related to Misoperations of Protection Systems and NERC's *State of Reliability* reports provided additional information to develop the proposed Reliability Standard.

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]**

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. The proposed standard also does not conflict with any existing regional differences, such as regional Reliability Standard PRC-004-WECC-1 (Protection System and Remedial Action Scheme Misoperation).

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

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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 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 PRC-004-3 has no undue negative effect on competition and does not unreasonably restrict transmission or generation operation on the Bulk-Power System.

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

The effective date for the proposed Reliability Standard appropriately balances the urgency to implement the standard against the time needed by those who must comply to develop necessary adjustments to procedures in support of the proposed Reliability Standard. To allow covered Entities adequate and reasonable time to comply with the proposed Reliability Standard, the effective date is twelve (12) months following the date that the proposed standard is approved.

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 G includes a summary of the standard development proceedings, and details the processes followed to develop the Reliability Standard. These processes included, among other

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.

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.

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.

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

NERC has not identified competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts 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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[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.

[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 E

Table of Issues and Directives

Table of Issues and Directives

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1460.	For the reasons stated in the NOPR, the Commission will not approve or remand PRC-003-1. (For reference) P 1458. In the NOPR, the Commission identified PRC-003-1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-1 until the ERO submitted the additional information.	PRC-004-3	PRC-003-1 will be retired and replaced by PRC-004-3.

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1461.	We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC-003-1 to provide missing information needed for the Commission to act on this Reliability Standard. (For reference) P 1459. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.	NERC Rules of Procedure, Section 1600 Request for Data or Information.	PRC-003-1 will be retired and replaced by PRC-004-3. The responsibility to address all aspects of a Protection System Misoperation is assigned to the owner(s) of the Protection System(s) - the Transmission Owner, Generation Owner, and Distribution Provider. Additionally, further consistency has been achieved by specifying the data reporting requirements for periodic Misoperations reporting based on a continent-wide template. All reporting of Misoperations will be done through a data request according to the NERC Rules of Procedures, Section 1600, Request for Data or Information instead of having PRC-004-3 specify an administrative reporting requirement.

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1469 (first directive only)	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1. (For reference) P 1466. ISO-NE further requests the Commission to direct NERC to modify PRC-004-1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO-NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO-NE provides the same suggestion with regard to PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1.	PRC-004-3 all Requirements.	PRC-004-2.1a will be retired and replaced by PRC-004-3.The Transmission Owner, Generator Owner, and Distribution Provider own the BES Protection Systems. The owners of BES Protection Systems have been assigned responsibility for this standard.

Exhibit F

Analysis of Violation Risk Factors and Violation Severity Levels

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

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-004-3 – Protection System Misoperation Identification and Correction.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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 VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) (“VRF Order”), *order on reh’g and compliance filing*, 120 FERC ¶ 61,145 (2007) (“VRF Rehearing Order”).
[2] *Id.* at fn 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of “High.” The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. The performance activity that has been isolated in Requirement R1 of PRC-004-3, to “review” (similar to “analyze”), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 (“…shall provide Facility Ratings (for its solely and jointly owned Facilities…”), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 (“…shall provide appropriate equipment characteristics and system data…”), IRO-015-1 – Special Protection System Data and Documentation, R1.1 (“…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.”), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 (“…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.”) which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 (“…shall provide documentation…”), PRC-016-0.1 – Special Protection System Misoperations, R3 (“…that owns an SPS shall provide documentation of the misoperation analyses…”), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 (“…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2			
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” This Requirement R4, to perform at least one “investigative action” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6			
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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 Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level 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 this Requirement.
FERC VSL G4 Violation Severity Level 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 G

Summary of Development History and Complete Record of Development

Summary of Development History

Project 2010-5.1 – Protection System (Misoperations)

The development record for proposed Reliability Standard PRC-004-3 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 ("SDT"). For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the team members is included in **Exhibit I**.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") was posted for informal comment from May 20, 2011 to June 3, 2011. The SAR was submitted to the Standards Committee ('SC") for approval on June 9, 2011.

B. First Posting - Formal Comment Period

Proposed Reliability Standard PRC-004-3 was posted for a 30-day public comment period from June 10, 2011 through July 11, 2011. There were 52 sets of comments, including comments from approximately 146 different individuals from approximately 106 companies, representing 10 of the 10 industry segments.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-004-3 and made the following observations and modifications based on those comments:

[1] *See*16 U.S.C. §824(d)(2) (2012).

- Modified the definition of Protection System Misoperation.
- An additional category of "Slow Trip-Other Than Fault" was added for consistency.
- Exclusion of Protection System operations because of on-site maintenance, testing, construction, or commissioning activities was added.
- An exclusion to the category "Unnecessary Trip-During Fault" was added related to the proper remote Protection System operation.
- Revised the standard by increasing the timelines and clarifying the steps involved to complete the investigation of a Misoperation.
- Revised the standard to clarify the starting point of the Misoperation investigation (new Requirement R2) is the occurrence of the Protection System operation.
- Revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "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."
- Revised the language in Attachment 1 of the categories to match the language approved for use in the revised Standard PRC-004.
- Removed the word "written".
- Redrafted the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C, and CMEP Section 3.1.4.2.
- Modified the Background statement to better reflect the interaction between this standard and the WECC regional Misoperations reporting standard.
- Changed the effective date (implementation time) to 12 months.

C. The Second Posting - Comment Period, Initial Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-004-3 was posted for a 45-day public comment period from July 25, 2012 through September 7, 2012. A Non-Binding poll of the VRFs and VSLs was conducted for the second comment posting for Reliability Standard PRC-004-3. There were 95 sets of comments, including comments from approximately 230 different individuals from approximately 145 companies representing 9 of the 10 industry segments. The proposed Reliability Standard received a quorum of 86.71% and an approval of 37.68%.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-004-3 and made the following observations and modifications based on those comments:

- The term ‘composite Protection System’ was incorporated into the introductory sentence of the definition to indicate that a Misoperation pertains to the ‘composite Protection System’ and clarify that only the overall performance of the Protection System is considered when determining a Misoperation.
- The definition categories were edited and revised to provide more specificity and clarity.
- Revised the Facilities portion of the Applicability section to provide more specificity.
- Revised Requirement R1 to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner.
- Revised Requirement R4, removing the parts to eliminate the administrative aspects.
- Modified the measures to complement the revised requirements.
- Added for clarity in Compliance 1.2 the following sentence: “The Transmission Owner Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.”
- Modified the boiler plate language for clarity.
- Removed the language from Compliance 1.4.
- Removed from the standard all reporting obligations.
- Changes made to the VSLs in conjunction with the revised requirements.
- Changes made to the Guidelines and Technical Basis corresponding to all changes to the standard.
- Revised the effective date from six months to twelve months following applicable regulatory approvals.
- Changes made to Implementation Plan.

D. The Third Posting - Comment Period, Successive Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-004-3 was posted for a 30-day formal comment period from January 22, 2013 through February 20, 2013. A Non-Binding poll of the VRFs and VSLs was conducted for the third comment posting for Reliability Standard PRC-004-3.There were 76 sets of comments, including comments from approximately 210 different individuals from approximately 132 companies representing all 10 of the industry segments. The proposed Reliability Standard received a quorum of 77.62% and an approval of 50.66%.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-004-3 and made the following observations and modifications based on those comments:

- The Standard drafting team proposed a new definition to support the revisions to the definition of Misoperation.
- Update occurrences were made of “composite Protection System” with the newly proposed term of Composite Protection System.
- Removed the uses of “zone”, and mostly notably updated the category of Slow Trip-During Fault” to address high-speed performance.
- Modified the last category of “Unnecessary Trip-Other Than Fault” to be clear that a Protection System operation due to on-site personnel is not a Misoperation.
- Reorganized the purpose statement to clarify that the standard applies to those Protection Systems for Bulk Electric System Elements.
- Revised the Facilities section of the Applicability to remove exclusions for Special Protection Systems (SPS) and Remedial Action Schemes (RAS).
- Exclusions concerning non-protective functions embedded within a Protection System and protective functions intended to operate as a control function has been moved to the main Applicability for Facilities to add clarity that these applicable as Protection Systems for Bulk Electric System (BES) Elements.
- Reorganized Requirement R1 to improve clarity of the required performance, allotted time periods, and a single reliability objective in a Requirement.
- Clarifying revisions made to Requirement R2 to pinpoint the Protection System component that caused the Misoperation as being subject to the (CAP).
- Added the word “first” before”…identifying the cause…” to improve clarity that upon identifying the “first cause” starts the 60 calendar day time period for developing the CAP.
- Added the clause “…and that no further corrective actions will be taken” to require entities to clearly state that no additional actions are planned to be taken to provide a measurable close to the performance in the declaration.
- The phrase “would reduce BES reliability” was replaced with “would not improve BES reliability” to align with those conditions where corrective action may not be practical.
- Requirement R3 was removed due to the use of “action plan” along with Corrective Action Plan created unnecessary confusion.
- Requirement R4 is nor Requirement R6 and is essentially the same as the previous Requirement R4, except that “action plan” was removed.
- Compliance section was corrected to comport with the standard language NERC uses in Reliability Standards.
- The Evidence Retention section was changed to reduce the minimum time periods that were previously proposed at six years for all Requirement to 12 calendar months for all Requirements according to the Standard Drafting Guidelines for evidence retention.
- Lowered Requirement R4 (implement the CAP) Violation Risk Level (VRF) from High to Medium.
- The violation Severity Levels were completely rewritten due to the substantive changes made in restructuring the Requirements to meet a single reliability objective in a requirement.

- Reorganized the Guidelines and Technical Basis section of the Application Guidelines for organization and flow.
- Section headers were added and reordered to create additional examples for guidance.

E. Fourth Posting- Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-004-3 was posted for a 45-day formal and public comment period from January 17, 2014 through March 11, 2014, with an additional ballot in the last 10 days of the comment. A Non-Binding poll of the VRFs and VSLs was conducted for the fourth comment posting for Reliability Standard PRC-004-3. There were 63 sets of comments, including comments from approximately 173 different individuals from approximately 99 companies representing 9 of the 10 of the industry segments. The proposed Reliability Standard received a quorum of 75.06% and an approval of 62.63%.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-004-3 and made the following observations and modifications based on those comments:

- Revised definition of "Composite Protection System" for clarity.
- Revised last category of "Unnecessary Trip-Other Than Fault" slightly to clarify that a Protection System operation caused by on-site personnel is not a Misoperation.
- "Composite" was inserted before "Protection System" for consistency with the proposed definition of "Composite Protection System".
- An exclusion for Remedial Action Schemes (RAS) and Special Protection System (SPS) has been provided to increase clarity that these Protection Systems are not applicable to the standard.
- Eliminated the extended implementation provision of 24 calendar months previously provided to entities in the Western Electric Coordination Council (WECC) Region.
- Inserted effective date language into Section 6 of the standard for completeness.
- Non-substantive revision made in Requirement R1 to more clearly describe that the BES interrupting device operation that meets the three sub-part (i.e., 1.1, 1.2, and 1.3).
- Revised Requirement R2 to address a gap in performance identified through continued review during the formal comment period.
- Revised Requirement R4 for clarity by adding "for a Misoperation" to more clearly reference the Misoperation identified in either Requirement R1 or R3.

- Updated each of the six Measures to provide the entity that is required to demonstrate compliance.
- Clarification was made for Requirement R5 that evidence retention related to the "development" of the Corrective Action Plan (CAP), each evaluation, and each declaration.
- Clarification was made to the Application Guidelines to note that timeframes are distinct and separate from the other Requirements.

F. Fifth Posting - Comment Period, Additional Ballot and Non-Binding Poll

Proposed Reliability Standard PRC-004-3 was posted for a 45-day public comment period from June 20, 2014 through July 9, 2014. A Non-Binding poll of the VRFs and VSLs was conducted for the fifth comment posting for Reliability Standard PRC-004-3. There were 47 sets of comments, including comments from approximately 136 different individuals from approximately 101 companies representing all 10 of the industry segments. The proposed Reliability Standard received a quorum of 76.98% and an approval of 74.53%.

The SDT considered stakeholder comments regarding proposed Reliability Standard PRC-004-3 and made the following observations and modifications based on those comments:

- Clarified the second sentence of the definition of "Composite Protection System" by changing the wording from "inclusionary" to an "exclusionary" statement.
- Clarified Requirement R1 by moving the clause "under the following circumstances" (referring to Part 1.1, 1.2, and 1.3).
- Added the clause with the clarifying reference to the Parts "under the circumstances in Parts 1.1 through 1.3" before the "shall" statement.
- Clarified Requirement R1, Part 1.3 based on a comment revealing an unintentional omission in the circumstances in which an entity is required to review a BES interrupting device operation.
- Clarified Requirement R2, Part 2.1 to include "manual intervention" as Requirement R1, Part 1.3 based on comments.
- Inserted the term "BES" in Requirement R2, Part 2.2 before "Element" to clarify that backup protection was provided for a condition on another entity's "BES Element" and not on another entity's non-BES Element,
- Clarified Requirement R4 by adding a parenthetical "(s)" to the second occurrence of "cause" for consistency with a previous occurrence in the Requirement.
- Added the clause "a minimum of" to the paragraphs pertaining to Requirements R1through R6 to clarify that the evidence retention periods stated in the Compliance section are minimum retention periods.

- Added the clause “following the completion of each Requirement” to add clarity that the minimum retention period applies to each Requirement.
- Clarified that evidence from R1 through R4 must be retained with the Corrective Action Plan.
- Deleted “or not” from each of the Requirement R1 Violation Severity Levels.
- Made grammatical corrections to text in the Rationale boxes associated with several Requirements.
- Rationale boxes will be moved to the end of the Guidelines.
- Consolidated text about time periods into its own section, “Requirement Time Periods”.
- Corrections made to the flowchart text to more closely align with the text in the Requirements.
- Corrected Implementation Plan to align the definition of “Misoperation,” category 2 and Applicability section concerning Facilities with the draft PRC-004-3 Reliability Standard.

G. Final Ballot

Proposed Reliability Standard PRC-004-3 was posted for a 10-day public comment period from July 29, 2014 through August 7, 2014. The proposed Reliability Standard received a quorum of 77.94% and an approval of 79.75%.

H. Board of Trustees Adoption

Proposed Reliability Standard PRC-004-3 was adopted by the NERC Board of Trustees on August 14, 2014.

Project 2010-05.1 Protection System (Misoperations)

Related Files

Status:

Adopted by the NERC Board of Trustees on August 14, 2014 and pending regulatory approval.

Purpose / Industry Need:

A key element for Bulk Electric System (BES) reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the root causes of Misoperations, will improve Protection System performance.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems) as a "fill-in-the-blank" standard and did not approve or remand the standard since the regional procedures had not been submitted. Since PRC-003-1 is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations). This could lead to a potential reliability gap. Additionally, regional procedures are not standardized among the regions, and preclude the development of consistent metrics for measuring Protection System performance.

Phase 1 of this project will develop an improved standard to support the analysis and mitigation of Misoperations. Later phases of this project will address Special Protection Systems and Remedial Action Schemes.

Additional Information:

This Project is also being used to meet one of the objectives identified within the ERO Strategic Goals for 2011-2015. In support of ensuring NERC has clear, high technical quality results-based reliability standards that provide for an adequate level of bulk power system reliability and that are delivered in a timely and efficient manner, the following objective was proposed:

- Modify the standards development process to allow rapid development of an initial draft standard by a small professional team with requisite expertise and skills, including legal and compliance, followed by subsequent stakeholder consensus review, comment and balloting; the process will provide early consultation, including with regulatory authority staff, to determine a clear set of objectives for the standard. The process will allow highest priority standards to be delivered to the board within one year.

NERC's Standard Processes Manual allows significant flexibility in the initial informal stages of SAR and standard development, and at this time, no changes to the standards development process are anticipated to be needed to meet this objective. When the informal "Rapid-Development Team" completes its work and submits it to the Standards Committee, the work will be posted for industry consideration and transitioned to a formal Drafting Team for further development under the regular rules defined in the Standards Process Manual.

Draft	Action	Dates	Results	Consideration of Comments
Draft 6 **PRC-004-3**	**Final Ballot** **Info>> (101)** **Vote>>**	**07/29/14 - 08/07/14 (Closed)**	**Summary>> (Updated) (102)** **Ballot Results>> (Updated) (103)**	

Clean (91) | Redline to Last Posted (92) Redline to Last Approved (93) **Implementation Plan** Clean (94) | Redline to Last Posted (95) **Supporting Documents:** **Mapping Document** Clean (96) | Redline to Last Posted (97) **VRF/VSL Justification** Clean (98)| Redline to Last Posted (99) Issues and Directives (100)				
Draft 5 **PRC-004-3** Clean (73) | Redline to Last Posted (74) **Implementation Plan** Clean (75) | Redline to Last Posted (76)	**Additional Ballot and Non-Binding Poll** Updated Info>> (83) Info>> (84) Vote>>	**06/20/14 - 07/09/14 (Closed)**	Summary>> (86) Ballot Results>> (87) Non-Binding Poll Results>> (88)	Consideration of Comments>> (90)

Supporting Documents: Unofficial Comment Form (Word) (77) **Mapping Document** Clean (78) | Redline to Last Posted (79) **VRF/VSL Justification** Clean (80) | Redline to Last Posted (81) Issues and Directives (82) **RSAW** Clean | Redline to Last Posted	**Comment Period** Info>> (85) Submit Comments>>	**05/16/14 - 07/09/14 (Closed)**	Comments Received>> (89)	
Draft 4 **PRC-004-3** Clean (56) | Redline to Last Posted (57) **Implementation Plan** Clean (58) | Redline to Last Posted (59) **Supporting Documents:**	**Additional Ballot and Non-binding Poll** Info>> Vote>>	**02/21/14 - 03/12/14 (Closed)**	Summary>> (68) Ballot Results>> (69) Non-Binding Poll Results>> (70)	Consideration of Comments>> (72)
	Comment Period Info>> (67)		Comments Received>> (71)	

Unofficial Comment Form (Word) (60) Mapping Document Clean (61) | Redline to Last Posted (62) VRF/VSL Justification Clean (63) | Redline to Last Posted (64) PRC-003-1 (65) PRC-004-1a (66)	Submit Comments>>	01/17/14 - 03/11/14 (Closed)		
	RAW Industry Comment Period Info>> RSAW RSAW Feedback Form>> Please send RSAW Feedback forms to: RSAWfeedback@nerc.net	02/18/14-03/19/14		
	Section 1600 Data Request			
Draft 3 PRC-004-3	Successive Ballot and Non-binding Poll	02/11/13 - 02/20/13 (Closed)	Summary>> (51)	

Clean (37) |Redline to Last Posted (38) **Implementation Plan** Clean(39) | Redline to Last Posted (40) **Supporting Documents:** Unofficial Comment Form (Word) (41) **Mapping Document** Clean(42) | Redline to Last Posted (43) **VRF/VSL Justification** Clean (44)| Redline to Last Posted (45) PRC-003-1 (46) PRC-004-1a (47) PRC-004-2 (48)	Info>> (49) Vote>>		**Updated** Full Record>> (52) Non-binding Poll Results>> (53)	Consideration of Comments>> (55)
	Comment Period Info>> (50) Submit Comments>>	**01/22/13 - 02/20/13 (Closed)**	Comments Received>> (54)	

Draft 2 **PRC-004-3** **Clean (19) | Redline (20)** **Implementation Plan** **Clean (21) | Redline (22)** **Attachment 1: Sample Data for Completion of Quarterly Misoperation Reporting Template (23)** **Supporting Documents:** **Unofficial Comment Form (Word) (24)** **Mapping Document (25)** **PRC-003-1 (26)** **PRC-004-1a (27)** **PRC-004-2 (28)** **VRF/VSL Justification (29)**	**Initial Ballot and Non-binding Polls:** **Info>> (30)** **Vote>>**	**8/29/2012 - 9/7/2012 (Closed)**	**Summary>> (32)** **Full Record>> (33)** **Non-binding Poll Results>> (34)**	
	Comment Period **Info>> (31)** **Submit Comments>>**	**7/25/2012 - 9/7/2012 (Closed)**	**Comments Received>> (35)**	**Consideration of Comments>> (36)**
	Join Ballot Pool **Join>>**	**7/25/2012 - 8/27/2012 (Closed)**		
Draft 1 **Draft PRC-004-3 (4)**	**Formal 30-day Comment Period**	**6/10/2011 - 7/11/2011 (Closed)**	**Comments Received>> (17)**	**Consideration of Comments>> (18)**

Quarterly Protection System Misoperation Reporting Template (Excel) Attachment 1: Sample Data for completion of Quarterly Misoperation Reporting Template (5) Implementation Plan (6) **Supporting Documents:** PRC-003-1 (7) PRC-004-1a (8) PRC-004-2 (9) VRF/VSL Justification (10) SPCS White Paper on Uniform Misoperations Reporting (11) NERC SPCS (12) Assessment of Standards: **PRC--003--1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems** **PRC--004--1 — Analysis and Mitigation of Transmission and Generation**	Info>> (16) Submit Comments>>			

Protection Misoperations PRC--016--1 – Special Protection System Misoperations **Issues Table (13)** **Requirements Mapping Document (14)** **Comment Form (Word) (15)**				
Draft SAR (3) **(Approved by the SC June 9, 2011)**	**Informal Comment Period** **(See question #10 of Survey)**	**6/10/2011 - 7/11/2011 (Closed)**		
Nominations for Protection System Misperations Standard Drafting Team **Nomination Form (Word) (1)**	**Info>> (2)** **Submit Nomination>>**	**5/20/2011 - 6/3/2011 (Closed)**		

All comments should be forwarded to sarcomm@nerc.net.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Nomination Form for Phase 1 of Protection Systems (Misoperations) Standard Drafting Team (Project 2010-05.1)

Please do not use this form. Please submit the electronic nomination form by 06/03/2011. If you have any questions, please contact Andy Rodriquez at andy.rodriquez@nerc.net.

By submitting the following information you are indicating your commitment to actively participate in drafting team meetings if appointed by the Standards Committee. This includes a commitment to travel to and attend face-to-face meetings of the drafting team (the average drafting team holds approximately six multi-day meetings per year), participate in conference call meetings of the drafting team (the average team meets by conference call approximately 20 times per year), and perform additional work outside of meetings as required. These obligations can be extended if work is not completed. You need to commit approximately 15% of your time over the next year and have your management's support to make this firm commitment.

Name:	
Current Title:	
Organization:	
Address:	
Telephone:	
Fax:	
Email:	

Project 2010-05.1 – Phase 1 of Protection Systems (Misoperations)

A key element of bulk power system reliability is the performance of the Protection Systems. To properly gauge Protection System performance, it is necessary to have a consistent set of metrics on Protection System Misoperations. Current PRC standards and definitions related to Protection System Misoperations are confusing and do not support a good metric for measurement of Protection System performance. There are no consistent misoperation categories and cause codes among all eight Regional Entities, which prevents meaningful analysis and measurement of Protection System performance. The System Protection and Coordination Subcommittee (SPCS) has recommended that a project be initiated to:

- Revise the definition of Misoperation (Reportable Protection Misoperation)
- Combine PRC-003-1 and PRC-004-1 into a single standard with revised requirements to

address the need for consistent reporting to support meaningful analysis of Protection System Misoperation, and withdraw existing standard PRC-003-1.

We are seeking industry experts in protection systems and events analysis to participate on this drafting team.

Please briefly describe your experience and qualifications directly related to the issues to be addressed by the drafting team for Project 2010-05.1.

Are you currently a member of any NERC or Regional Entity SAR or standard drafting team? If yes, please list each team here.

☐ No

☐ Yes:

Have you previously worked on any NERC or Regional Entity SAR or standard drafting teams? If yes, please list them here.

☐ No

☐ Yes:

Please identify the NERC Region(s) in which your company operates and for which you are able to represent your company's position relative to the applicable issues while serving on the drafting team:

☐ ERCOT	☐ MRO	☐ RFC	☐ SPP
☐ FRCC	☐ NPCC	☐ SERC	☐ WEC

☐ Not Applicable or None of the Above

Please identify the industry segment(s) you can represent on behalf of your company while serving on the drafting team:

☐	1 — Transmission Owners
☐	2 — RTOs and ISOs
☐	3 — Load-serving Entities

☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	Not applicable

Based on your expertise or responsibilities, please identify which of the following Functional Entities[1] you can represent on behalf of your company while serving on the drafting team:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Please provide the names and contact information for two references whom we have permission to contact for attestation to your technical qualifications and your ability to work well in a group:

Name and Title:		Office Telephone:	
Organization:		E-mail:	
Name and Title:		Office Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC website.

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Standards Announcement

Project 2010-05.1 Protection System Misoperations
Drafting Team Nomination Period Open
May 20 – June 3, 2011

The Standards Committee is seeking industry experts to serve on the Protection System Phase 1 - Misoperations Standard Drafting Team. This drafting team will draft revisions to the definition of Misoperation as well as revisions to combine PRC-003 and PRC-004 into a single standard.

If you are interested in serving on this drafting team, please complete this nomination form **by June 3, 2011**.

Project Background

A key element for Bulk Electric System (BES) reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the root causes of Misoperations, will improve Protection System performance.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 (Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems) as a “fill-in-the-blank” standard and did not approve or remand the standard since the regional procedures had not been submitted. Since PRC-003-1 is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2 (Analysis and Mitigation of Transmission and Generation Protection System Misoperations). This could lead to a potential reliability gap. Additionally, regional procedures are not standardized among the regions, and preclude the development of consistent metrics for measuring Protection System performance. This project will develop an improved standard to support the analysis and mitigation of Misoperations.

In addition, to ensure NERC has clear, technically correct, results-based reliability standards that provide for an adequate level of bulk power system reliability and that are delivered in a timely and efficient manner, NERC has a goal to modify the standards development process to allow rapid development of an initial draft standard by a small professional team with requisite expertise and skills, including legal and compliance, followed by subsequent stakeholder consensus review, comment and balloting. The proposed process provides early consultation, including with regulatory authority staff, to determine a clear set of objectives for the standard. The process could allow highest priority standards to be delivered to the board in a shorter time period than experienced when a larger drafting team is appointed to develop a standard later in the standard development process.

Project 2010-05.1 Protection Systems Misoperations was chosen as a pilot to evaluate one approach for accomplishing this goal. In this approach, an ad hoc team made up of subject matter experts and other diverse skill sets, including legal, compliance, and regulatory expertise will deliver a SAR and draft standard to the Standards Committee (as is allowed within the rules of the current Standards Development process). This delivery will occur in early June.

The Standards Committee is seeking candidates to proceed with the remaining steps of refining and balloting the standard using the normal standard development process.

The Standards Committee is seeking industry experts in protection systems and events analysis to participate on this drafting team.

Further details are included on the Project 2010-05 project page:
http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Eleanor Crouch,
Standards Administrative Assistant, at eleanor.crouch@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Standard Authorization Request Form

Title of Proposed Standard	Protection System Misoperation Identification and Correction
Request Date	June 9, 2011

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name: NERC Pilot Rapid Development Team	☐	New Standard
Primary Contact: Al McMeekin	☒	Revision to existing Standard (revise Misoperation definition; combine PRC-003-1, PRC-004-1a, and PRC-004-2)
Telephone: (803) 530-1963 Fax	☒	Withdrawal of existing Standard (PRC-003-1)
E-mail: al.mcmeekin@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

A key element for Bulk Electric System (BES) reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the root causes of Misoperations will improve Protection System performance.

Industry Need (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.)

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 as a “fill-in-the-blank” standard and did not approve or remand the standard since the regional procedures had not been submitted.

Since PRC-003-1 is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2. This could lead to a potential reliability gap.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

- Revise the definition of Misoperation
- Combine PRC-003 and PRC-004, and retire standard PRC-003.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

This project will revise the existing definition of Misoperation, which reads:

Misoperation (current definition)

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

Misoperation data, as currently collected and reported, is not usable to establish a consistent metric for measuring Protection System performance. The NERC Pilot Rapid Development Team recommends establishing a standard with uniform applicability, revising the definition of Misoperation and clarifying reporting requirements.

Furthermore, the proposed requirements of the revised Reliability Standard PRC-004-3 should meet the following objectives:

- Review all Faults or Protection System operations on the BES to identify those that are BES Protection System Misoperations
- Analyze BES Protection System Misoperations to determine the cause(s)
- Develop and implement Corrective Action Plans to address the causes of BES Protection System Misoperations

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	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.
☐	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 box for 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 reliability 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? *(Select 'yes' or 'no' from the drop-down box.)*
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
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**
PRC-003-0	Retire
PRC-004-1a	Retire
PRC-004-2	Retire
PRC-003-STD-1	Overlaps, but no conflict (compliance is not mutually exclusive, and

	complying with the more stringent standard will ensure the less stringent standard is met)
PRC-004-WECC-1	Overlaps, but no conflict (compliance is not mutually exclusive, and complying with the more stringent standard will ensure the less stringent standard is met)

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	Check

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 (Dates of posting).
2. SC authorized moving the SAR forward to standard development (SC meeting date when authorized).

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)

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	June 9, 2011
45-day Formal Comment Period with Parallel Initial Ballot	September 16, 2011
Recirculation ballot	December 19, 2011
BOT adoption	February 13, 2012

Effective Dates: Requirement R1 and its associated parts shall become effective on the first day of the first calendar quarter, 3 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 3 months after Board of Trustees adoption.

Version History

Version	Date	Action	Change Tracking

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 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

Any of the following:

1. **Failure to Trip - During Fault** - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect.

2. **Failure to Trip - Other Than Fault** - Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

3. **Slow Trip** - Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect.

4. **Unnecessary Trip - During Fault** - Any Protection System operation for a Fault not within the zone it is designed to protect.

5. **Unnecessary Trip - Other Than Fault** - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.
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 for Facilities that are part of the BES.

   4.2.2 Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Under Voltage Load Shedding programs are excluded from this standard.

5. **Background**:

   A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 as a "fill-in-the-blank" standard and did not approve or remand the standard since the regional procedures had not been submitted.

   Since PRC-003-1 is not enforceable, there is no mandatory requirement for the Regional Entity procedures to support the requirements of PRC-004-2. This represents a potential reliability gap.

   This project includes revising the existing definition of Misoperation, which reads:

   Misoperation

   - Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
   - Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).

- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

Misoperation data, as currently collected and reported, is not usable to establish a consistent metric for measuring Protection System performance. The SAR includes establishing a standard with uniform applicability, revising the definition of Misoperation, and clarifying reporting requirements.

The proposed requirement of the revised Reliability Standard PRC-004-3 meets the following objectives:

- Review all Faults and Protection System operations on the BES to identify those that are BES Protection System Misoperations.
- Analyze BES Protection System Misoperations to determine the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of BES Protection System Misoperations.

The reporting of Misoperations associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding has not been addressed in this standard due the complexity of the subject matter. NERC intends to address these areas through a separate project in the future.

Note that there are two WECC standards, PRC-003-STD-1 and PRC-004-WECC-1, related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where those standards will overlap with the Continent-wide standard, entities are expected to comply with the more stringent standard. Doing so will ensure compliance with the less stringent standard as well. There are no apparent conflicts between the standards that would lead to mutually exclusive compliance.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*]

1.1 A detailed description of the processes used to:

1.1.1 Document and review all BES Faults and BES Protection System operations.

1.1.2 Identify and document all associated Misoperations, if any.

1.1.3 Investigate and address each Misoperation.

1.2 A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s) and do one of the following:

- For each Misoperation where the cause(s) are identified, document the investigation and the cause(s).
- For those cases where the cause(s) are not identified, document the investigation, any cause(s) that were ruled out, and any additional steps planned to identify the cause(s).

1.3 A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days of the Misoperation, develop one of the following:

- A Corrective Action Plan (CAP) that includes:
  1. Interim corrective actions (if any).
  2. Final corrective or mitigating actions to reduce potential impacts to BES reliability.
  3. A work timetable.
- A declaration explaining why there is no need to develop a CAP.

1.4 A requirement that for all Misoperations for which the cause(s) was (were) not identified, the Registered Entity shall, within 120 calendar days of the Misoperation, develop one of the following:

- An action plan that identifies:
  1. Additional investigative actions and/or Protection System modifications.
  2. A work timetable.
- A declaration that includes an explanation of why no further investigation or actions will be taken.

1.5 A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented.

Rationale for R1: This requirement mandates entities have a process to identify and correct Protection System Misoperations. A review of the Transmission Availability Data System (TADS) data for the past three years reveals that the fourth ranked initiating cause of BES outages not related to weather is “Failed Protection System Equipment.” By developing more structure regarding the manner in which Misoperations are identified and corrected, risks to the BES caused by Misoperations can be reduced by ensuring that certain mandatory practices are consistently undertaken. Further, such consistency will also enhance reporting and the development of performance metrics that indicate overall system health, as well as facilitate the sharing of “lessons learned.”

M1. The Transmission Owner, Generator Owner and Distribution Provider shall have a current copy of its procedure for identifying and addressing Misoperations in accordance with Requirement R1.

M2. The Transmission Owner, Generator Owner and Distribution Provider shall have dated written lists of Faults, Protection System operations, and identified Misoperations with their associated date of occurrence to demonstrate implementation of the procedural elements related to Requirement R1, Part 1.1.

M3. The Transmission Owner, Generator Owner and Distribution Provider shall have a dated written investigation report for each Misoperation identifying either cause(s), or where the cause(s) of the Misoperation cannot be identified, any additional steps planned for identifying causes to demonstrate implementation of the procedural elements related to Requirement R1, Part 1.2.

M4. To demonstrate implementation of the procedural elements related to Requirement R1, Part 1.3, the responsible entity shall have, for each Misoperation with an identified cause or causes, a dated CAP or a dated written declaration explaining why there is no need to develop a CAP.

M5. To demonstrate implementation of the procedural elements related to Requirement R1, Part 1.4, the responsible entity shall have, for each Misoperation without an identified cause or causes, a dated written action plan that includes a work timetable for implementation or a dated written declaration explaining why no further investigation or actions will be taken.

M6. The responsible entity shall have dated evidence, such as work management program records or work orders or other dated evidence, to demonstrate implementation of any plans completed during the implementation of the procedural elements related to Requirements R1, Part 1.5.

M7. The responsible entity shall have dated documentation that describes the manner in which the each CAP or action plan was completed to demonstrate compliance with the procedural elements related to Requirements R1, Parts 1.5

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Transmission Owner, Generator Owner and each Distribution Provider that owns a BES Protection System shall retain data or evidence to show compliance with Requirement R1 and Measures M1, M2, M3, M4, M5, M6, and M7 for six calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Compliance Monitor shall retain any audit data for six years.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the time specified above, whichever is longer.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

Periodic Data Submittal: Within 60 calendar days following the end of each calendar quarter, each Transmission Owner, Generator Owner, and each Distribution Provider that owns BES protection Systems will submit a quarterly report to its Regional Entity that lists all Protection System Misoperations identified in accordance with Requirement R1 using the format specified by the ERO. Each responsible entity will include the status of each of its Misoperation CAPs or action plans developed until these CAPs or action plans are reported complete.

The Regional Entity will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Assessment, Operations Planning**	**High**	The responsible entity documented the investigation and either identified the cause or listed the additional steps planned to identify the cause in more than 90 calendar days but less than or equal to 120 calendar days following the Misoperation.	The responsible entity documented the investigation and either identified the cause or listed the additional steps planned to identify the cause in more than 120 calendar days but less than or equal to 130 calendar days following the Misoperation.	The responsible entity documented the investigation and either identified the cause or listed the additional steps planned to identify the cause in more than 130 calendar days but less than or equal to 140 calendar days following the Misoperation.	The responsible entity did not have a procedure to identify and address all Protection System Misoperations. OR The responsible entity failed to implement its procedure to identify and address all Protection System Misoperations. OR The responsible entity documented the investigation and either identified the cause or listed the additional steps planned to identify the cause in more than 140 calendar days following the Misoperation. OR

						The responsible entity failed to document the investigation and identify the cause or list the additional steps planned to identify the cause.
			OR	OR	OR	OR
			The responsible entity developed and documented a CAP or a declaration in more than 120 calendar days but less than or equal to 150 calendar days following the Misoperation.	The responsible entity developed and documented a CAP or a declaration in more than 150 calendar days but less than or equal to 160 calendar days following the Misoperation.	The responsible entity developed and documented a CAP or a declaration in more than 160 calendar days but less than or equal to 170 calendar days following the Misoperation.	The responsible entity developed and documented a CAP or a declaration in more than 170 calendar days following the Misoperation.
				OR	OR	OR
				The responsible entity developed and documented a CAP but failed to include one of the elements listed in Requirement R1, Part 1.3.	The responsible entity developed and documented a CAP but failed to include two of the elements listed in Requirement R1, Part 1.3.	The responsible entity failed to develop and document a CAP or a declaration following a Misoperation.
			OR	OR	OR	OR
			The responsible entity developed and documented an action plan or a declaration in more than 120	The responsible entity developed and documented an action plan or a declaration in more than 150 calendar	The responsible entity developed and documented an action plan or a declaration in more than 160 calendar	The responsible entity developed and documented an action plan or a declaration in more than 170 calendar

			calendar days but less than or equal to 150 calendar days following the Misoperation.	days but less than or equal to 160 calendar days following the Misoperation.	days but less than or equal to 170 calendar days following the Misoperation. OR The responsible entity developed and documented an action plan but failed to include the delivery dates in accordance with the work timetable specified in Requirement R1, Part1.4. OR The responsible entity implemented the CAP or other action plan, but did not meet the completion timeline stated in the plan.	days following the Misoperation. OR The responsible entity failed to develop and document an action plan or a declaration following a Misoperation. OR The responsible entity failed to implement a CAP or other action plan.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

A revised Misoperation definition is being proposed for industry adoption. It includes the following conditions:

(1) Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. A lack of target information, e.g. when a high-speed pilot system does not trip because a high-speed zone element trips first, is not a Misoperation. If a fault or abnormal condition is cleared within the time normally expected with proper functioning of at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation.

(2) Any failure of a Protection System to trip for a non-Fault condition such as power swings, over excitation, or loss of excitation for which the Protection System was intended to operate. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation.

(3) Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect. Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems.

(4) Any Protection System operation for a Fault not within the zone it is designed to protect. An example of this type of Misoperation is an over-reaching trip due to a lack of coordination between Protection System relays. Note: Operation of properly coordinated backup Protection System relays to clear the fault in an adjacent zone is not a Misoperation if the primary protection fails to clear the fault within the specified time.

(5) Any Protection System operation for non-Fault conditions such as power swings, over excitation, or loss of excitation for which the Protection System is not intended to operate. For example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation.

This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.

Failure to automatically reclose after a fault is not included as a Protection System Misoperation because reclosing equipment is not included under the definition of Protection Systems. Operations which are initiated by control systems (not by Protection Systems), such as those associated with generator controls, or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are also not Misoperations of a Protection System.

Requirement R1 states the overall objective of the standard, which is to ensure that entities have and consistently implement a procedure to identify and correct all Protection System Misoperations. Specific detail regarding what this procedure must include is provided in the **Parts 1.1 through 1.5**.

Part 1.1 requires that entities have a process to review all events for potential Misoperations and identify all Misoperations found. Reviewing all events associated with Faults on the BES and reviewing all BES Protection System Operations is necessary for reviewing all events which may be associated with BES Protection System Misoperations. The process of identifying a Misoperation from an analytical standpoint begins with a review of all situations that challenge Protection Systems. Faults are one of the major sources of challenge to the BES Protection System. A fault does not need to occur on the BES to result in a BES Protection System Misoperation. To completely identify Misoperations, it must be determined if the Protection System operated for a Fault within its zone of protection, a Fault outside its zone, or a no-Fault condition. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed Faults resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

Given that a Misoperation has been identified, **Part 1.2** requires the responsible entity accurately identify the underlying or "root" cause in sufficient detail to develop a corrective action plan that remedies the problem to prevent Misoperation recurrence. The cause of most Misoperations can be identified without extraordinary effort. Where a cause cannot be identified, a thorough documentation of the investigation is required to aid future investigation of the Misoperation particularly if it recurs. It is expected that the responsible entity will perform due diligence to identify the Misoperation cause.

An investigation report generally includes the following information: 1) initial evidence, 2) probable or potential causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records. The probable (or potential) causes are a list of those causes which are most likely to have contributed to the Misoperation and could be considered for testing. The test and studies documented in the report would describe and provide findings of those tests (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the root cause. The conclusions should summarize the root cause(s) substantiated by the evidence and findings of the tests and studies.

If no root cause was found, then the conclusions would attest to the indeterminate results and delineate those causes that have been eliminated.

Part 1.2 gives 90 calendar days from the date of the Misoperation to complete the investigation. The 90 day allowance was selected to provide sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes. This standard applies to all BES Protection Systems some of which are more critical than others. It is assumed that critical systems will be addressed with more urgency which may delay the investigation of less critical systems. Some regional standards (such as PRC-004-WECC-1) may identify those critical elements and provide more stringent time frames.

In most cases where a root cause of a Misoperation is identified, a Corrective Action Plan to address the cause will improve the performance and reliability of the BES. **Part 1.3, Bullet 1** establishes the need for an entity to have a procedure for developing Corrective Action Plans. A Corrective Action Plan should include interim corrective actions, final corrective actions, and a timeline for completion delivery dates. Interim corrective actions may be useful to quickly address some of the aspects of the Misoperation prior to implementation of a final solution. Examples for interim corrective actions are: disabling a blocking scheme prior to conversion to a permissive scheme, and taking equipment offline or removing equipment from service until new equipment is available.

The reliability of the BES could be greatly enhanced by making it immune to faults. Protection Systems are applied to the BES to clear faults and contain their negative impacts, thereby maintaining the reliability and stability of the BES. However, it is impossible (or at least highly impractical) to create failure proof Protection Systems. This is particularly true of Protection Schemes which rely on substation to substation communications for proper operation. The communication equipment can be spread over large distances, and be exposed to failure causes beyond the capability of the Protection System's owner's capability to control. Part of proper application of these Protection Systems involves analysis of their behavior during communication failures.

Where studies have determined that high speed clearing is required over 100% of the protected element to maintain stability, a communication failure must not prevent high speed fault clearing. In general, this will result in some amount of tripping for external faults. That, by definition, is a misoperation. There are usually things that can be done to reduce the tendency to misoperate, and to reduce the impact of a misoperation. However, the possibility typically cannot be eliminated. Altering the Protection System to eliminate tripping for every possible over trip during communication failures would prevent this type of misoperation, but it would negatively impact the stability of the BES.

Where studies have determined that excessive tripping is a greater threat to stability than slow tripping for a remote end line fault, permissive schemes can be used to provide high speed tripping. These schemes provide security against excessive tripping during communication failures, but will result in slower tripping for some faults. Under the proposed Misoperation definition, this may not always be considered a Misoperation, but it is certainly less than optimal Protection System performance. It does promote system stability however. Improving the likelihood of high speed clearing at the expense of security in these cases, will negatively impact the stability of the BES.

In rare cases such as the one described above, where altering a Protection System to avoid the recurrence of a Misoperation may lower the reliability or performance of the BES, a declaration addressing the lack of a CAP is required. Additionally, if analysis of the event shows that the cause of the failure is beyond the Protection System owner's ability to prevent or correct (such as a communication failure caused by an external dig in), corrective action may not be appropriate.

Part 1.3 Bullet 2 allows for this situation by requiring that where corrective action is not taken, the Protection System owner has to provide a declaration that includes a description of the failure mode, the Misoperation, and the potential impacts on the BES of eliminating the mode of Misoperation.

While many things can be done to improve the performance of Protection Systems, it is not possible to prevent all failures. Protection Systems which are designed to operate during partial failure modes in a manner that promotes the maintenance of BES stability may experience Misoperations for which a Corrective Action Plan may not be appropriate.

In some cases, analysis of all available information will not identify a root cause. **Part 1.4** is intended to allow entities to deal with these scenarios and still meet the overall objectives of the reliability standard.

In some of these cases additional steps may be identified (such as applying more monitoring equipment) to aid in future investigations of subsequent Misoperations. Modifications to the Protection System may be identified which could reduce the likelihood of a recurrence of the Misoperations. These steps and modifications should be identified to aid in future investigations of recurring Misoperations.

When a root cause is not identified and all investigative avenues have been exhausted, a declaration detailing the description of the investigative work conducted as well as the justification for the decision to conclude the investigation is required.

Parts 1.3 and 1.4 both give 120 calendar days from the date of the Misoperation to develop a plan or otherwise address the Misoperation. This give an additional 30 days beyond the deadline established on **Part 1.2.** As discussed above, this allowance provides sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes. Also as discussed above, some regions may choose to implement more stringent deadlines for some of all of its Protection Systems.

Finally, the goal of the standard has not been met unless action plans are actually implemented, as is required in **Part 1.5.** The responsible entity is required to implement and complete a CAP or other action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The CAP or action plan is intended to correct the root causes of Protection System Misoperations and prevent them from recurring. The responsible entity is also required to complete the CAP or action plan, document the manner in which the plan was implemented, and retain the appropriate evidence to demonstrate implementation.

This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

A review of the Transmission Availability Data System (TADS) data for the past three years reveals that the fourth ranked initiating cause of BES outages not related to weather is “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.

Section C-1.4 requires periodic data reporting and references a common reporting format to facilitate consistent reporting of Misoperation data by all Transmission Owners, Generator Owners, and Distribution Providers. Reporting Misoperation data in a common format permits the ERO to analyze the data, develop meaningful metrics for measuring Protection System performance, identify trends in Protection System performance that negatively impact reliability, and identify lessons learned.

Analysis of data from all Misoperations across North America makes possible identification of issues and trends that may not be identifiable through analysis of smaller data sets on an entity or regional basis. Information regarding identified issues and trends and recommended actions will be shared with Transmission Owners, Generator Owners, and Distribution Providers through lessons learned or industry alerts. Sharing this information will permit recipients to take appropriate actions to drive improvements in Protection System performance.

The common reporting template also will improve the usefulness of metrics developed to track Protection System performance. While the most relevant category defined in TADS is titled "Failed Protection System Equipment," the title is not an accurate description of the information reported in the metric. This metric includes all Protection System Misoperations that are not related to human error, which is only a subset of all Protection System Misoperations. The Protection System Misoperations related to human error (e.g., miscoordinated settings, incorrect setting calculations, and errors in applying settings to the relay, etc.) are tracked separately from Protection System equipment-related Misoperations, and are grouped together with other human errors by a utility employee or contractor. Similarly, Protection System Misoperations related to failed equipment such as a failed CVT on the primary insulation side are reported under "Failed AC Substation Equipment." Reporting of Misoperations data using the common format specified in **C-1.4** will permit development of metrics specific to Protection System Misoperations, with the potential to break down the metric by category of Misoperation (e.g., failure to trip, slow trip, unnecessary trip, etc.) and cause of Misoperation (ac system, dc system, as-left personnel error, incorrect setting/logic/design, and relay failures/malfunctions).

Attachment 1: Quarterly Misoperations Reporting Data

Field Name	Field Description	Example Data
Resubmittal Check	Identify if this is a resubmission of data. **Field Value:** Yes or No	No
Regional Entity	Identify Regional Entity. **Field Value:** FRCC, MRO, NPCC, RFC, SERC, SPP, TRE, or WECC	SERC
Entity Name	Enter Entity name. **Field Value:** User-defined Text	National Power
Misoperation Date	Enter the date of the Misoperation. **Field Value:** MM/DD/YYYY format	5/25/2010
Misoperation Time	Enter the time of the Misoperation. **Field Value:** HH:MM:SS format (use 24 hour clock)	10:02:31
Time Zone	Identify time zone. **Field Value:** ADT, AST, CDT, CST, EDT, EST, MDT, MST, PDT, PST, or GMT	EDT
Facility Name	Identify the name of the substation or generating station Facility where the Misoperation occurred. **Field Value:** User-defined Text	Lois Lane
Equipment Name	Identify the name of the generator, transmission line, transformer, bus or equipment protected by the Protection System that Misoperated. **Field Value:** User-defined Text	Kent - Lois Lane 115 kV line
Equipment Type	Identify the type of equipment being protected. **Field Value:** Line, Transformer, Generator, Shunt Capacitor, Series Capacitor, Bus, Shunt Reactor/Inductor, Series Reactor/Inductor, Dynamic Var Systems, Breaker, HVdc, or Other	Line
Facility Voltage (kV)	Identify the system voltage of the protected element (For transformers, use high-side voltage). **Field Value:** <100, 100, 115, 120, 138, 161, 230, 345, 500, 735, 765, or HVdc	115
Equipment Removed from Service	Identify the equipment removed from service (sustained or momentary - less than one minute) because of the Misoperation. **Field Value:** User-defined Text specifying the Circuits, Transformers, Buses (and also Breakers only if the Breaker is the only element to trip)	Lois Lane-Kent 115 kV line
Event Description	Provide a brief description of the event and detailed description of Misoperation root cause(s). **Field Value:** User-defined Text	Primary Ground Relay (KRP) failed to operate.

		Resulted in slow clearing at Lois Lane Substation. At Lois Lane, field found KA-4 relay with failed RRH/RRT coil that prevented a trip output from the KRP Primary ground relay.
Misoperation Category	Identify the Misoperation Category. **Field Value:** Failure to Trip – During Fault, Failure to Trip – Other Than Fault, Slow Trip, Unnecessary Trip – During Fault, or Unnecessary Trip – Other Than Fault	Slow trip
Cause(s) of Misoperation	Identify the root cause(s) of the Misoperation	Relay failures/malfunctions
	Field Value: AC System - This category includes Misoperations caused by problems with the AC source to the Protection System equipment. Examples include Misoperation caused by CT saturation, loss of potential and rodent damage to voltage or current circuit wiring.	
	Field Value: As-left Personnel Error - This category includes Misoperations caused by incorrect as-left Protection System element settings following maintenance or construction activities. Examples include leaving test switches open, wiring errors where correct drawings were provided for use, leaving carrier grounds in place, installing the wrong relay settings, and making incorrect field settings during calibration testing.	
	Field Value: Communication Failure - This category includes Misoperations caused by protection scheme communication system failure include failure of installed transmitters and receivers. Examples include Misoperation caused by loss of carrier, spurious transfer trips associated with noisy channels, leased-line failure or performance issues caused by telephone company error, loss of fiber optic communication equipment, and microwave communication problems caused by weather conditions.	
	Field Value: DC System - This category includes Misoperations caused by problems with the DC source to Protection System equipment. Examples include problems with the battery, battery charging system, circuit breaker trip circuits, or loss of DC power to a relay or communication device.	

	Field Value: Incorrect Setting/Logic/Design Errors - This category includes Misoperations caused by Protection System owner engineering staff errors. Examples include setting errors, errors contained in provided documentation, application errors, failure to coordinate settings, incorrect schematics and drawings, and having a protection scheme with multiple CT ground connections installed as specified by provided design drawings.	
	Field Value: Relay Failure/Malfunction - This category includes Misoperations caused by incorrect operation of Protection System relays. Examples include component failure, equipment physical damage, firmware problems, manufacturer error, aging capacitors causing a change in relay characteristics, misfiring thyristors, water damage, relay power supply failure, internal relay wiring/logic error and failure of protection scheme auxiliary tripping relays.	
	Field Value: Unknown/Unexplainable - This category includes Misoperations that occur for which a bonafide cause cannot be determined. If selecting this cause code as Misoperation root cause, then detailed documentation of investigative actions performed justifying selection of this cause code is required to be created and maintained for review.	
Protection Systems/Components that Misoperate	Provide information on the protection systems/components that misoperate. Also list the relay model(s) and protection scheme(s) involved if the Cause(s) of Misoperation is identified as either "Relay Failure/Malfunction" or "Incorrect Settings/Logic/Design Errors". **Field Value:** User-defined Text	KRP ground relay and KA-4 used in DCB scheme
Relay Technology	Identify the relay technology installed if the Cause(s) of Misoperation is "Relay failures/malfunctions" or "Incorrect settings/logic/design errors". **Field Value:** Electromechanical, Solid State, or Microprocessor	Electromechanical
TADS Reportable Outage?	Identify if this outage is a TADS reportable outage. **Field Value:** Yes or No	No
TADS Cause Code	The corresponding TADs Cause Code is automatically added to this record if the outage is a TADS reportable outage. **Field Value:** (No entry required)	Not a Reportable TADS outage
TADS Event ID(s)	Enter each TADS Event ID(s) associated with the Misoperation event using TADS Form 5 if the outage is a TADS reportable outage. **Field Value:** User-defined Text	N/A
Analysis and Corrective Action Status	Identify Misoperation investigation and resolution status. **Field Value:** Analysis - In Progress, Analysis - Completed, Corrective Action - In Progress, or Corrective Action - Completed	Analysis - Completed
Corrective Action Plan	Identify the corrective actions taken. **Field Value:** User-defined Text	The powerline carrier

		transceiver at Lois Lane is scheduled to be replaced due to an unrelated failure. This KA-4 relay will be replaced at that time.
CAP Target Completion Date	Enter the Corrective Action Plan target completion date. **Field Value:** MM/DD/YYYY format	12/31/2010
Actual CAP Completion Date	Enter the Corrective Action Plan actual completion date. **Field Value:** MM/DD/YYYY format	
Reported By	Identify the reporting Entity point of contact. **Field Value:** User-defined Text	Tom Jefferson
Phone Number	Identify the reporting Entity point of contact phone number. **Field Value:** User-defined Text	959-867-5309
E-Mail Address	Identify the reporting Entity point of contact E-Mail address. **Field Value:** User-defined Text	TJ@NPI.net
Date Reported	Enter the report date. **Field Value:** MM/DD/YYYY format	6/30/2010

Implementation Plan for PRC-004-03

Standards Involved:

- Approval:
  - PRC-004-3 – Protection System Misoperation Identification and Correction

- Retirements:
  - PRC-003-1— Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems
  - PRC-004-1a — Analysis and Mitigation of Transmission and Generation Protection System Misoperations
  - PRC-004-2 — Analysis and Mitigation of Transmission and Generation Protection System Misoperations
- Related
  - PRC-003-STD-1, PRC-004-WECC-1: These are two regional standards related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where those standards will overlap with the Continent-wide standard, entities are expected to comply with the more stringent standard. Doing so will ensure compliance with the less stringent standard as well. There are no apparent conflicts between the standards that would lead to mutually exclusive compliance.

Prerequisite Approvals:
The proposed standard is **not** dependent on any prerequisite approvals.

Revision to Sections of Approved Standards and Definitions:
There is one revised definition for the proposed standard:

Misoperation: Any of the following:

1. **Failure to Trip - During Fault -** Any failure of a Protection System to operate for a Fault within the zone it is designed to protect.
2. **Failure to Trip - Other Than Fault -** Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.
3. **Slow Trip -** Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect.
4. **Unnecessary Trip - During Fault -** Any Protection System operation for a Fault not within the zone it is designed to protect.
5. **Unnecessary Trip - Other Than Fault -** Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.

Retirement of Existing Standards:
The existing Standards PRC-003-1, PRC-004-1a, and PRC-004-2 shall be retired upon regulatory approval of PRC-004-3.

PRC-003-1 is currently not enforceable, but requires the establishment of a procedure by the RRO. The new PRC-004-3 puts this obligation on the Functional Entities instead, and specifies the minimum elements required in the procedure, making PRC-003-1 unnecessary and duplicative.
PRC-004-1a and -2 Requirements R1 and R2 require the Functional Entities implement the procedures specified in PRC-003-1. R1 in the new PRC-004-3 includes this obligation. R3 in PRC-004-1A and -2 requires reporting to the RRO, which has now been included in the Compliance section of the standard. Together, these elements make PRC-004-1A and -2 superfluous as well.

Applicability:
This standard applies to the following functional entities:

- Transmission Owners
- Generator Owners
- Distribution Providers

This standard applies to the following Facilities:

- Protection Systems for Facilities that are part of the BES.
- Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Under Voltage Load Shedding programs are excluded from this standard.

Effective Date:
The effective date is the date entities are expected to meet the performance identified in this standard.

Requirement R1 and its associated parts shall become effective on the first day of the first calendar quarter, 3 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect on the first day of the first calendar quarter, 3 months after Board of Trustees adoption.

Because the standard does not deviate significantly from what is required today, it is believed that this standard can be implemented on a relatively short schedule.

A. Introduction

1. **Title:** **Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**

2. **Number:** PRC-003-1

3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Regional Reliability Organization

5. **Effective Date:** May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:

R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).

R1.2. Data reporting requirements (periodicity and format) for Misoperations.

R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.

R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.

R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.

M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.

M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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.	01/20/06

A. Introduction

1. Title: **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. Number: PRC-004-1a

3. Purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. Applicability

4.1. Transmission Owner.

4.2. Distribution Provider that owns a transmission Protection System.

4.3. Generator Owner.

5. Effective Date: To be determined

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1.a	February 17, 2011	3. Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1.a	February 17, 2011	Adopted by the Board of Trustees	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

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Violation Risk Factor and Violation Severity Level Assignments

2010-05.1 – Phase 1 of Protection Systems (Misoperations)

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in the following draft standards:

- PRC-004-3 — Protection System Misoperation Identification, Correction and Reporting

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.

Justification for Assignment of Violation Risk Factors

The Protection Systems Misoperations Rapid Development Team applied the following NERC criteria when proposing VRFs for the requirements under this project:

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.

The RDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs[1]:

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors 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:[2]

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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[1] North American Electric Reliability Corp., 119 FERC 61,145, order on reh'g and compliance filing, 120 FERC 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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 RDT considered the FERC VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Guideline 1 identifies a list of topics that encompass nearly all topics within the NERC 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 on the reliability of the system. The RDT believes that Guideline 4 better reflects the intent for assigning VRFs since this approach is focused on the reliability impact of the requirement.

VRF for PRC-004-3:

There is one requirement in PRC-004-3. The VRF was determined as follows:

VRF for PRC-004-3, Requirements R1: HIGH

- FERC Guideline 2 — Consistency within a Reliability Standard exists, as there is only one requirement in the standard.
- FERC Guideline 3 — Consistency among Reliability Standards exists. The requirement is similar to EOP-004-1 R2, which was assigned a "Medium" VRF. However, the RDT believes specifying a "High" VRF is appropriate because this requirement, unlike EOP-004-1 R2, requires that entities also implement a procedure to correct the causes of Misoperations to prevent their reoccurrence in the future.
- FERC Guideline 4 **—** Consistency with NERC's Definition of the VRF Level selected exists. Not correcting the cause or causes of a Protection System Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Accordingly, the VRF has been established as "High."
- FERC Guideline 5 **—** Treatment of Requirements that Co-mingle More Than One Obligation is satisfactory. The Requirement does not co-mingle more than one obligation. All Parts are related to the creation and implementation of the procedure to identify and correct the causes of Protection System Misoperations.

Justification for Assignment of Violation Severity Levels:

In developing the VSLs for the standards under this project, the RDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The RDT based its assignment of VSLs on the following NERC criteria:

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 VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in standards under this project meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 per violation per day basis is the “default” for penalty calculations.

VSLs for PRC-004-3 Requirement R1:

R#	Compliance with NERC VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	The NERC VSL guidelines are satisfied by grading of the requirement. Because of the interdependence of the various Parts and the manner in which they contribute to the ultimate goal of correcting Misoperations, each Part has been considered independently, and missing a precursor Part has the potential to result in a Severe violation.	PRC-003-1 proposed VSL elements are similar to PRC-004-2 approved VSL elements. Complete failures to analyze Misoperations are treated as Severe violations, similar to the current standard. Proposed VSL assignments do not have the unintended consequence of lowering current compliance.	Proposed VSLs are graded and address each of the Parts of the requirement. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties.	Proposed VSL's do not expand on what is required in the requirement. Proposed VSL's are consistent with the requirement, and all Parts of the requirement have been addressed in the VSLs.	Proposed VSL's are based on a single violation and not a cumulative number of violations.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SPCS Input on Uniform Misoperations Reporting

NERC System Protection and Control Subcommittee

to ensure the reliability of the bulk power system

November 19, 2010

116-390 Village Blvd., Princeton, NJ 08540
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1. Background

The NERC System Protection and Control Subcommittee (SPCS) was requested to provide input to the ERO Reliability Assessment and Performance Analysis (ERO-RAPA) Group regarding development of a consistent format and specification for Registered Entities to report protection system misoperation data to the Regions under NERC Reliability Standards PRC-003 and PRC-004. The SPCS assigned a team to develop proposals for SPCS consideration and the full SPCS discussed these proposals during its November 9-11, 2010 meeting. SPCS recommendations were forwarded by e-mail on November 10. This report provides formal documentation of the recommendations forwarded previously.

2. Reporting Template

SPCS comments on the ERO-RAPA Group proposed template are provided in an additional column added by the SPCS for this purpose. The SPCS agrees with the information to be collected in the template provided the template is used to collect data under PRC-004 (as is currently planned). However, in the event that agreement is not reached by the regions on a common reporting format and the template is used to collect data specifically for the purpose of reliability metric ALR4-1, then the template should collect only the data required for the metric; i.e., in this case the Corrective Action Plan information should be excluded from the template.

The SPCS comments provided in the template are focused primarily on ensuring that enough clarity is provided to obtain consistent reporting of information. The SPCS is available to review these comments with the ERO-RAPA Group and provide more detail. The work necessary to fully develop the format includes items such as development of drop-down boxes, etc., and the SPCS is available to work with NERC Staff or the ERO-RAPA Group to develop the specifics.

The template, with SPCS comments, is provided in Attachment A of this report.

3. Misoperation Categories

The SPCS recommends four misoperation categories as presented below in Table 1. The categories include two categories related to Protection System dependability and two categories related to Protection System security. These four categories are very similar to what is currently used by most regions.

Table 1: Misoperation Categories

Misoperation Categories
Failure to Trip
Slow trip (i.e., slower than required to meet TPL requirements)
Unnecessary Trip during fault
Unnecessary Trip other than fault

4. Cause Codes

The SPCS recommends six Cause Codes as presented below in Table 2. Cause codes also are based on current regional procedures. Adopting these six Cause Codes will require reporting more detail for some regions and less for others. The SPCS believes that these six Cause Codes strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance, while avoiding confusion and inconsistent reporting that may occur with too many Cause Codes.

Table 2: Cause Codes

Cause Codes	Cause Code Description
Incorrect setting/logic/design errors	This category includes misoperations due to "engineering" errors by the protection system owner. These include setting errors, errors in documentation, and errors in application. Examples would include uncoordinated settings, incorrect schematics, or multiple CT grounds in the design.
Relay failures/malfunctions	This category includes misoperations due to improper operation of the relays themselves. These may be due to component failures, physical damage to a device, firmware problems, or manufacturer errors. Examples would include misoperations caused by changes in relay characteristic due to capacitor aging, misfiring thyristors, damage due to water from a leaking roof, relay power supply failure, or internal wiring error. Failures of auxiliary tripping relays fall under this category.
Communication failures	This category includes misoperations due to failures in the communication systems associated with protection schemes inclusive of transmitters and receivers. Examples would include misoperations caused by loss of carrier, spurious transfer trips associated with noise, Telco errors resulting in malperformance of communications over leased lines, or microwave problems associated with weather conditions.
As-left personnel error	This category includes misoperations due to the condition the protection system was left in following maintenance or construction procedures. These include test switches left open, wiring errors not associated with incorrect drawings, carrier grounds left in place, or settings placed in the wrong relay.
AC system	This category includes misoperations due to problems in the ac inputs to the protection system. Examples would include misoperations associated with CT saturation, loss of potential, or rodent damaged wiring in voltage or current circuit.
DC system	This category includes misoperations due to problems in the DC control circuits. These include problems in the battery or charging systems, trip wiring to breakers, or loss of dc power to a relay or communication device.
Unknown/unexplainable	Requires extensive documentation of investigative actions if this cause code is utilized.

5. Applicability

During its discussion the SPCS noted that input had not been requested on the subject of the system Elements for which Protection System misoperations should be reported. The SPCS noted that because regional differences presently exist, it is necessary to provide guidance on this subject to achieve uniform reporting. The SPCS has previously provided input on this subject during its review of PRC-003, PRC-004, and PRC-016.[1] The SPCS discussed this subject and decided to update its previous recommendation to reflect FERC communications, modifications to the NERC Statement of Compliance Registry Criteria, and other industry developments that have occurred since May 2009.

The SPCS proposes that reporting of misoperations under PRC-004 apply to the Protection Systems defined below.

Protection Systems which trip:

a. Transmission system elements 100 kV and above

b. Transformers with 100 kV or higher on the secondary side

c. Generators that meet the definition in the NERC Statement of Compliance Registry Criteria and are connected to the transmission system at 100 kV or higher

d. Generator step-up transformers for generators that meet the definition in the NERC Statement of Compliance Registry Criteria and are connected to the transmission system at 100 kV or higher

[1] NERC SPCS Assessment of Standards: PRC-003-1, PRC-004-1, and PRC-016-1, May 22, 2009.

APPENDIX A – Draft Reporting Template with SPCS Comments

Field Name Common to All Regions Entity Name	Necessary Field Name Entity Name	Other Desired Information* Field Name	Information Explanation Name of Entity which owns the facility	SPCS Comments
Misoperation Date	Misoperation Date		Enter the date of the Misoperation	
	Misoperation Time		Enter the time of the Misoperation in (24 hr.) HH:MM:SS format	
	Time Zone		The time zone of the reported time of the Misoperation	*Include a drop-down menu for time zone entry (include GMT as one of the drop-down entries).*
		Equipment lost	Names of the equipment becoming unavailable due to the event	*Need to provide more specific instructions: e.g., define transmission lines by terminals and voltage; define transformers by substation name and terminal voltages*
	Facility Name Location of Misoperation)		Identify the name of the facility (i.e., substation or generating station) where the Misoperation occurred	*Suggest using another term than "facility" to avoid confusion with NERC defined term, "Facility"*
	Equipment Name (protected by Protection System that Misoperated)		Identify by name the generator, transmission line, transformer, bus or equipment protected by the Protection System that Misoperated	*Need to provide more specific instructions: e.g., define transmission lines by terminals and voltage; define transformers by substation name and terminal voltages*
	Equipment Type		Type of equipment being protected (e.g. Generator, Line, Capacitor, Transformer, Bus, Inductor, or Other)	*In order to obtain consistency in naming; dropdown menus will be helpful*
	Facility Voltage		System voltage (in kV) of the protected element (if transformer, high side kV)	
Event Description	Description of Event		Provide a brief description of the event and Misoperation	
	Protection Systems that Misoperated		Information on the Protection Systems that Misoperated including relay types and protection schemes	*In order to obtain consistency in naming; dropdown menus will be helpful*
	Misoperation Category		Categories include (but not limited to): Failure to Trip, Slow Trip,	*The SPCS recommends four Misoperation Categories (Failure*

Field Name Common to All Regions Entity Name	Necessary Field Name Entity Name	Other Desired Information* Field Name	Information Explanation Name of Entity which owns the facility	SPCS Comments
			Unnecessary Trip During Fault, Unnecessary Trip Other than Fault, Under Review	*to Trip; Slow trip (i.e., slower than required to meet TPL requirements); Unnecessary Trip during fault; Unnecessary Trip other than fault*
	Cause(s) of Misoperation		Identification of the root cause(s) of the Misoperation	*Reporting the Cause of Misoperation should include two fields: one for a description and one to enter the Cause Code (SPCS recommends six Cause Codes)*
Corrective Action Plan and Investigation	Corrective Action Plan and Investigation		Identify the investigations and corrective actions taken or being taken	*Corrective Action Plan information is appropriate for inclusion in the template for reporting under PRC-004-1. If the regions do not reach agreement and the template is used for a Section 1600 Data Request to collect data for ALR4-1, then the Corrective Action Plan information should be deleted from the template.*
	Proposed Completion Date		If corrective actions are not complete, estimate when they will be complete	*See note above.*
	Completion Date		If corrective actions are complete, enter the completion date	*See note above.*
	Reported By		Enter the name of the person filling out the report	
	Phone		Enter the reporting person's phone number	
	E-Mail		Enter the reporting E-MAIL address	
	Date Reported		The date that the Misoperation is/was reported to the Region	

APPENDIX B – System Protection and Control Subcommittee Roster

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC SPCS Assessment of Standards:

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems
- PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations
- PRC-016-1 – Special Protection System Misoperations

A Technical Review of Standards

Prepared by the

System Protection and Controls Subcommittee

of the

NERC Planning Committee

May 22, 2009

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Introduction

When the original scope for the System Protection and Control Task Force (SPCTF, now the System Protection and Control Subcommittee – SPCS) was developed, one of the assigned items was to review all of the existing PRC-series of Reliability Standards, to advise the Planning Committee, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCS' assessment of three of the PRC standards pertaining to relay misoperations:

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems
- PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations
- PRC-016-1 – Special Protection System Misoperations

This report serves as a precursor for a Standards Authorization Request (SAR) for modifications to PRC-003 that will be submitted by the SPCS.

Executive Summary

Standard PRC-003 is intended to ensure that all System Protection Misoperations are analyzed and mitigated according to guidelines established by the regions. The FERC, in Order 693, dated March 16, 2007, declared this standard as a “fill in the blank” type of standard that does not merit approval unless it is modified to make it more specific and consistent for all Regions. The SPCS concurs with the FERC order and provides recommendations on how the standard can be rewritten.

Because the procedures for analyzing and mitigating Misoperations were to be established by the regions, there is significant dissimilarity between the Misoperation data reported by each region, resulting in a virtually unusable misoperation metric for North America. SPCS recommends a change to the definition of Misoperation (Reportable Protection Misoperation) to provide uniformity to the misoperation data reported to the regions and NERC.

Protection System elements used for Special Protection Systems (SPS) or Remedial Action Schemes (RAS) are no different from those used for non Special Protection Systems. The revision to Standard PRC-003 should therefore apply to all Protection Systems, including SPS and RAS.

The SPCS also recommends that Standard PRC-016-0 – Special Protection System Misoperations, be requirements, merging its SPS/RAS Misoperation reporting, Corrective Action Plans, and tracking requirements into PRC-004 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations.

Whenever an SPS/RAS misoperates and requires a Corrective Action Plan, that plan should become subject to review under PRC-012 to ensure that the changes proposed to the SPS are still properly designed, meet performance requirements, and is coordinated with other Protection Systems. Therefore, PRC-012 should be revised to require that review and PRC-004 should be modified to refer to that review process.

A Standards Authorization Request (SAR) will be submitted by the SPCS calling for a standards project to:

- Revise the definition of Misoperation (Reportable Protection Misoperation)
- Modify PRC-003, PRC-004, and PRC-012
- Retire PRC-016.

Assessment of PRC-003-1

PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires the regions to establish procedures for analysis of Misoperations. This has resulted in significant and substantive differences in regional procedures and this was noted in FERC's recommendation for "greater uniformity."

SPCS proposes updating the PRC-003-1 standard to be applicable to all regions based on following tenets:

1. **Applicability** – The existing standard says that the Protection Systems shall be reviewed but does not specify which systems apply to this standard.

   It is necessary for the new standard to define the protections systems to which the standard applies:

   - Transmission Protection Systems which trip:
     a. Transmission system elements 200-kV and above
     b. Operationally significant system elements 100-kV to 200-kV
     c. Transformers with 100-kV or higher on the low side
     d. GSU transformers with high side voltages of 100-kV or higher
   - Generation Protection Systems which trip:
     a. Transmission system elements 200-kV and above
     b. Operationally significant system elements 100-kV to 200-kV
     c. Transformers with 100-kV or higher on the low side
     d. GSU transformers with high side voltages of 100-kV or higher
     e. Generators connected through GSU transformers with high side voltages of 100-kV or higher
   - Protection Systems that trip aggregate generation of 75 MW or more (such as wind farms, geothermal, or solar) connected to the transmission system at 100-kV or higher.

2. **Definitions** – The NERC Glossary of Terms currently defines Misoperation as:

   Misoperation (current definition)
   - Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.

- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

The existing definition does not address what are reportable and non-reportable misoperations. Reportable misoperations should be redefined in terms of both dependability and security, as a function of the impact of the Protection Systems on the electric system performance. SPCS recommends the following definition:

Reportable Protection Misoperation (proposed definition)

Dependability (failure to operate):

- Failure of the composite Protection System to initiate the isolation of a faulted power system Element as designed or within its designed operating time.
- Failure of the composite Protection System to operate as intended for a non-fault condition, such as out-of-step, overload, etc., within its designed operating time.
- Failure of an SPS/RAS, UVLS system, or UFLS system to operate for an intended condition or within its designed operating time.

Security (false or undesirable operations):

- Improper operation of a Protection System in absence of a fault on the power system Element it is designed to protect.
- Improper operation of a Protection System during a fault on any other power system Element it is not designed to protect.
- Improper operation of an SPS/RAS, UVLS system, or UFLS system in absence of its designed trigger conditions.
- Over-response of an SPS/RAS, UVLS system, or UFLS system

Notes to the proposed definition:

A. The composite Protection System in the context of this standard is the total complement of protection for a system Element (line, bus, transformer, generator, etc). Primary and secondary protection of a given Element is considered as the composite Protection System, not two separate Protection Systems.

B. *Delayed clearing, where a high-speed system is employed and is essential for transmission system performance, is considered a reportable misoperation of the high-speed system.*

C. *Lack of targeting of the high-speed system, such as when it is beat out by a high-speed zone, is not considered a reportable misoperation.*

D. *Multiple misoperations of a Protection System before it can be reasonably investigated and remedied should be considered as a single misoperation.*

E. *Failure to automatically reclose after a fault is not a reportable misoperation.*

F. *Human errors made in protection settings either as calculated or as installed, or wiring errors, which result in a misoperation are reportable.*

G. *Protection System operations related to on-site maintenance, testing, construction and or commissioning activities for that Protection System, when no fault or other abnormal condition has occurred, are not considered reportable Protection System misoperations.*

H. *Operations which are initiated by control systems (not by the Protection Systems), such as those associated with generator controls or turbine/boiler controls, SVCs, FACTS, HVDC, circuit breaker mechanism, or insulation media, or other facility control systems, are not reportable Protection System misoperations.*

I. *Protection System operations which occur with the protected element already out of service, that do not trip any in-service elements, are not reportable Protection System misoperations.*

3. **Reporting of Misoperations –** Because the current PRC-003 calls for regional procedures and reporting requirements, there is a wide variation in those requirements from region to region, making comparison of misoperations metrics at the NERC level virtually impossible. Since any assessment of the success or failure of the NERC protection-related standards to maintain or improve reliability depends on those metrics, it is important to provide for uniformity.

   The variations in definitions can be corrected by the adoption of the Reportable Protection Misoperation definition above.

   Uniform reporting can be addressed by following proposed reporting requirements:

   - Transmission Owner or Generation Owners that own Protection Systems shall submit a quarterly report of the total number of events analyzed, the number of Protection System misoperations, and the number of events still under analysis, in a prescribed format (to be part of the revised PRC-003 standard) no later than two calendar months after each quarter.

- The regions shall, in turn, submit a quarterly report to NERC – consolidated data for the Region in a prescribed format (also part of the revised PRC-003 standard).
- The regions shall provide any additional information on misoperations to NERC as requested.

4. **Analyses of All Protection System Operations –** All transmission and generation Protection System operations should be analyzed to determine if the operation was correct. Merely reporting the number of misoperations is meaningless unless put in the context of the total number of operations.

5. **Peer Review of Misoperations –** Peer review of misoperations and tracking of mitigation plans is an important part of improving Protection System performance. Logically, that function should be done by the Regional Entities. However, since standards requirements cannot be placed on the Regional Entities, the following suggestions are made but the mechanics are left open.

   - The regions, through their appropriate committees or subcommittee, shall review the misoperation reports. This review should determine whether further analysis, data, or other documentation is required, and it will confirm that appropriate mitigation is defined and scheduled.
   - The regions should maintain records of the quarterly reports and confirm the implementation of any proposed mitigation plan.
   - The regions should track the mitigation of reported misoperations to avoid further occurrences.

Assessment of PRC-004 and PRC-016-0

NERC standards PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, and PRC-016 – Special Protection System Misoperations both require that Protection System misoperations are analyzed and reported, and that corrective actions are taken where necessary. However, PRC-016 exclusively applies to special protection systems (SPS), also know as remedial action schemes (RAS). Since analysis and reporting of protection system misoperations is the same regardless of whether or not a SPS/RAS is involved; there is no need for a separate standard. Standard PRC-004-1 should be revised to include SPS/RAS, and PRC-016 should be retired.

SPS Corrective Action Plan Review

PRC-012-0 – Special Protection System Review Procedure is intended to provide a review procedure to ensure that all SPS/RAS are properly designed, meet performance requirements, and are coordinated with other Protection Systems.

Whenever an SPS/RAS misoperates and requires a Corrective Action Plan, that plan should become subject to review under PRC-012 to ensure that the changes proposed to the SPS are still properly designed, meet performance requirements, and are coordinated with other Protection Systems. Therefore, PRC-012 should be revised to require that review and PRC-004 should refer to that review process.

Proposed PRC-004-1 Revisions

SPCS recommends the following revisions to PRC-004-1 requirements to encompass those of PRC-016:

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System or SPS shall each analyze its transmission Protection System or SPS Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature in accordance with Standard PRC-003 (revised).

R2. The Generator Owner shall analyze its generator Protection System or SPS Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature in accordance with Standard PRC-003 (revised).

R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a transmission Protection System or an SPS shall provide documentation of the misoperation analyses and the Corrective Action Plans to its Regional Reliability Organization and NERC upon request (within 90 calendar days).

R4. All Corrective Action Plans for SPS shall be subject to SPS Review Procedures in accordance with Standard PRC-012.

Appendix A – System Protection and Control Subcommittee

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Table of Issues and Directives Associated with PRC-003-1			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Fill in the Blank Team	368. Review PRC-003 and PRC-004 together to identify the specific requirements of the functional entities (include specific requirements for each functional entity).	PRC-003-1 will be retired, replaced by PRC-004-3. Responsibility to develop procedures has been reassigned to the Transmission Owner, Generation Owner, and Distribution Provider in revised standard PRC-004-3, and specific elements that are required to be in those procedures have been enumerated. The RRO has been deleted from the Applicability section.	PRC-004-3 Applicability section and Requirement R1.
Fill in the Blank Team	369. This is a North American Standard as written which places requirements on the regions to develop a procedure. However, PRC-004 requires functional entities to comply with the procedures the RROs develop. Craft a new PRC-003 as a North American standard.	Rather than place an obligation on the regions, this new standard requires specific procedural elements that must be implemented by the Functional Entities.	PRC-004-3 Applicability section and Requirement R1.
Fill in the Blank Team	370. Modify PRC-003 to include specific requirements for each functional entity. Each of the regional plans needs to be reviewed to determine what should be included in the North American standard. The current PRC-003 defines requirements for RROs. The drafting	The new standard includes a specific requirement for the Functional Entities. Prior work by the regions to develop uniform reporting requirements has been taken into account, and the standard incorporates these lessons learned.	PRC-004-3 Requirement R1 and the format specified by the ERO (referenced in Section 1.4 Additional Compliance

Table of Issues and Directives Associated with PRC-003-1			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
			Information).
Version 0 Team	371. Need to define evidence	PRC-003-1 will be retired, replaced by PRC-004-3. Language of revised standard PRC-004-3 has greater clarity with respect to prior versions. Each Measure clearly identifies the kind of evidence necessary for compliance. Requirement R1 also contains Parts which specify the evidence required for drafting a Corrective Action Plan, action plan, or declaration.	PRC-004-3 Measures M1 through M7 and Requirement R1
Version 0 Team	372. Change wording to reporting instead of monitoring	PRC-003-1 will be retired, replaced by PRC-004-3. Revised standard PRC-004-3 language conveys a different context with greater clarity than prior versions. The words monitor, monitoring or reporting are not used in the standard requirements. The word report is used in revised standard PRC-004-3 Measure M2 (context: investigative report) and also PRC-004-3 Section 1.4 Additional Compliance Information requires functional entities to report Misoperations data quarterly.	PRC-004-3 Measure M2 and Section 1.4 Additional Compliance Information.

Table of Issues and Directives Associated with PRC-003-1			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Phase III/IV Team	373. Enhance the applicability section to clarify that the systems addressed by the requirements are limited to:	The team recognizes the definition of the BES is under development and does not want to preclude the efforts of that team with regards to the applicability of this standard. Adding specific limitations as suggested would possibly require extensive modification once the BES definition is completed. Additionally, the Phase II/IV team offers no justification for excluding elements of the BES form this standard.	PRC-004-3 Applicability section.
Phase III/IV Team	374. All transmission circuits 200 kV and above	The team recognizes the definition of the BES is under development and does not want to preclude the efforts of that team with regards to the applicability of this standard. Adding specific limitations as suggested would possibly require extensive modification once the BES definition is completed. Additionally, the Phase II/IV team offers no justification for excluding elements of the BES form this standard.	PRC-004-3 Purpose, Applicability Section, and Requirement R1 .
Phase III/IV Team	375. All transmission circuits 100 kV to 200 kV operationally significant circuits, as defined by the RROs	The team recognizes the definition of the BES is under development and does not want to preclude the efforts of that team with regards to the applicability of this standard. Adding specific limitations as suggested would possibly require extensive modification once the BES definition is completed. Additionally, the Phase	PRC-004-3 Purpose, Applicability Section, and Requirement R1 .

Table of Issues and Directives Associated with PRC-003-1			
Source	Directive Language (including pg #)	Disposition	Section and/or Requirement(s)
		II/IV team offers no justification for excluding elements of the BES form this standard.	
Phase III/IV Team	376. Generator protection systems, whose misoperations impact the bulk electric system	The team recognizes the definition of the BES is under development and does not want to preclude the efforts of that team with regards to the applicability of this standard. Adding specific limitations as suggested would possibly require extensive modification once the BES definition is completed.	PRC-004-3 Applicability section and Requirement R1 .
Phase III/IV Team	377. The RRO should be required to demonstrate that the requirements developed in accordance with R1 produce the desired result.	The standard now removes the ability of an RRO to develop a deficient procedure. Instead, it specifically enumerates several procedural elements that, if implemented, will produce the desired result.	PRC-004-3 Applicability section, Requirement R1, and VSLs.
Phase III/IV Team	378. In R1.2 change format to content	Revised standard PRC-0004-3 language conveys a different context with greater clarity than prior versions. The revised standard does not include the words format or content.	N/A

Table of Issues and Directives Associated with PRC-003-1			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
NERC	659. Modify standard to conform to the latest version of NERCs Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure	PRC-003-1 will be retired, replaced by PRC-004-3. The revised standard PRC-004-3 is based on the new RBS format with development work based on the latest version of the NERC Standard Drafting Team Guidelines and ERO Rules of Procedure.	Reliability standard PRC-004-3.
FERC Order 693	1077. Consider if greater consistency can be achieved in the standard as suggested by APPA.	Greater consistency has been provided by establishing the core elements that must be included in any entity's procedure for identifying and correcting Protection System Misoperations. Additionally, further consistency has been created by specifying the format for periodic compliance reporting.	PRC-004-3 Applicability section, Requirement R1 and Section 1.4 Additional Compliance Information.

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Fill in the Blank Team	379. Review PRC-003 and PRC-004 together to identify the specific requirements of the functional entities.	PRC-003-1 will be retired. PRC-003-1 assigned responsibility to the RRO to maintain procedures for identification through resolution of BES Misoperations. Responsibility has been reassigned to the Transmission Owner, Generation Owner, and Distribution Provider in revised standard PRC-004-3 which requires a review of all events to identify all BES Misoperations. The RRO has been deleted from the Applicability section. PRC-004-2 essentially requires the Transmission Owner, Generator Owner, and Distribution Provider to identify and correct BES Misoperations per the RRO procedure and to also report BES Misoperation data to the RRO. Reference to the RRO procedure has been deleted and the co-mingled actions of Requirements R1 and R2 have been unbundled into 5 separate requirements in revised standard PRC-004-3. Requirement R3 is now the Periodic Data submittal language of Section 1.4 Additional Compliance Information in the latest version of PRC-004.	PRC-004-3 Applicability section, Requirement R1 , and Section 1.4 Additional Compliance Information.

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Fill in the Blank Team	380. See notes for PRC-003-1.	Fill in the Blank Team comments 368-370 for PRC-003-1 have been considered with disposition drafted to reference PRC-003-1, PRC-004-2 and the revised standard PRC-004-3 as appropriate.	N/A
Fill in the Blank Team	381. Coordinate the revision of this standard with the revision to standard PRC-003. PRC-003 needs to be written as a North American standard with requirements for each functional entity as appropriate. Once PRC-003 is modified, the only changes needed to PRC-	Both PRC-003-1 and PRC-004-3 were reviewed. PRC-003 and not PRC-004 will be retired because PRC-003 assigns procedure responsibility to the RRO. It is more appropriate to incorporate the salient ideas of PRC-003 into the revised PRC-004 standard. The revised standard PRC-004-3 specifies the BES Misoperations obligations of the Transmission Owner, Generator Owner, and Distribution Provider. These functional entities are required to review of all events to identify all BES Misoperations	PRC-004-3 Applicability section and Requirement R1.
Version 0 Team	382. Levels of non-compliance need to be redefined	Revised standard PRC-004-3 Levels of non-compliance are defined consistent with the NERC VSL drafting guidelines	PRC-004-3 VSLs.

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Phase III/IV Team	383. This standard should apply to all protection systems on the Bulk Electric System (BES) not just those that 'impact' the BES	Revised standard PRC-004-3 Requirement R1 language includes the phrase, “all events involving BES Faults or BES Protection System operations associated with its Facilities” to identify and document all Misoperations. This language ensures that all events, whether initiated by a BES Protection System or not, are reviewed to determine if a Misoperation occurred.	PRC-004-3 Requirement R1,
NERC Audit Observation Team	587. Document the process	The revised standard PRC-004-3 identifies the specific procedural elements associated with identifying and correcting Misoperations.	PRC-004-3 Requirement R1
NERC Audit Observation Team	588. The Generator Owner shall analyze its generator protection system Misoperations and implement corrective action plans to avoid future Misoperations.	The revised standard PRC-004-3 Applicability section includes the Transmission Owner, Generator Owner, and Distribution Provider. The applicability section also includes a Facilities subsection that identifies Generator BES Protection Systems applicable to this reliability standard. Each Requirement makes reference to BES Protection Systems.	PRC-004-3 Applicability section and Requirement R1.

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
Compliance	667. Joel deJesus, June 2010 - Please review and update as necessary the data retention period. A number of standards provide for data retention periods that are shorter than the normal audit cycle either specifying that only the current document need be retained or that the data need only be retained for a time period (30-days, 60-days, 90-days, etc.) shorter than the normal 3-year or 6-year audit cycle. This inconsistency between data retention periods and audit periods creates an unintended inconsistency. Changes to the Compliance Monitoring and Enforcement Program (CMEP) that are being applied to the Regional Delegation Agreements (RDA) in 2010, provide for the following: The Registered Entity will be expected to demonstrate compliance for the entire period described above. However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard, with the Reliability Standard for failing to produce a document for a period earlier than	The revised standard PRC-004-3 Evidence Retention section requires a 6 calendar year evidence retention period.	PRC-004-3 Evidence Retention.

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
	the start of the retention period specified in the Reliability Standard; However, in such cases, Compliance Audit team the Compliance Enforcement Authority will require the Registered Entity to demonstrate will test compliance through other means. Language in the standards regarding data retention should track this same thought. That would mean deleting any provision that requires only the retention of the current document, and by indicating that while other documents need only be retained for a short time(30-days, 60-days, 90-days, etc.), the standard should indicate that The Registered Entity will be expected to demonstrate compliance for the entire period described above.		
FERC Order 693	1079. Consider ISO-NE's suggestion that LSEs and transmission operators should be listed as applicable entities.	LSE and transmission operators do not own BES Protection Systems or apparatus. The owners of the equipment have been assigned responsibility for this standard.	PRC-004-3 Applicability section

Table of Issues and Directives Associated with PRC-004			
Source	**Directive Language (including pg #)**	**Disposition**	**Section and/or Requirement(s)**
FERC Order 693	1080. The regional entity should develop procedures for corrective action plans.	The revised standard establishes specific elements that must be included in the procedure for identifying and correcting Protection System Misoperation. In so doing, the obligation for the Regional Entity to undertake this effort has been removed. Instead, consistent with the need for the Reliability Standards to apply to the users, owners, and operators of the BES, that obligation now resides with the entities themselves.	PRC-004-3 Requirement R1,
NERC	659. Modify standard to conform to the latest version of NERCs Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure	The revised standard PRC-004-3 is based on the new RBS format with development work based on the latest version of the NERC Standard Drafting Team Guidelines and ERO Rules of Procedure.	Reliability standard PRC-004-3.

Mapping Document Showing Translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, and PRC-004-2 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into PRC-004-3 — Protection System Misoperation Identification and Correction

Standard: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	PRC-004-3 Requirement R1 replaces the Regional Reliability Organization with the Transmission Owner, Generator Owner, and Distribution Provider as the Responsible entity(s) for reviewing events to identify all Misoperations. Additionally, the Standard has specified the minimum elements that must be included in the procedure.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**

R1, Part 1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	PRC-004-3 Requirement R1, Part 1.1 specifies, using glossary terms, all events involving BES Faults or BES Protection Systems operations are reviewed to identify all Misoperations.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **R1.1.** A detailed description of the processes used to: **1.1.1** Document and review all BES Faults and BES Protection System operations. **1.1.2** Identify and document all associated Misoperations, if any. **1.1.3** Investigate and address each Misoperation.
R1, Part 1.2. Data reporting requirements (periodicity and format) for Misoperations.	PRC-004-3 Section 1.4 Additional Compliance Information specifies submitting Misoperation data on a quarterly basis using the format specified by the ERO. The format for data submission is based on the current TADS reporting template.	**1.4. Additional Compliance Information** **Periodic Data Submittal:** Within 60 calendar days following the end of the calendar quarter, each Transmission Owner, Generator Owner, or Distribution Provider that owns BES protection Systems will submit a quarterly report to its Regional

		Entity, identifying all Misoperations in accordance with Requirement R1using the format as specified by the ERO. Each Misoperation shall be updated on a quarterly basis until the CAP or action plan is reported complete. The Regional Entity will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.
R1, Part 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	PRC-004-3 Requirement R1 specifies the owner of the BES Protection System that Misoperated shall develop and document a Corrective Action Plan or declaration if cause is known, and that the owner of the BES Protection System that Misoperated shall develop and document an action plan or declaration if cause is not known.	**R1.2.** A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s) and do one of the following: • For each Misoperation where the cause(s) are identified, document the investigation and the cause(s). • For those cases where the cause(s) are not identified, document the investigation, any cause(s) that were ruled out, and any additional steps planned to identify the cause(s). **R1.3.** A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered

		Entity shall, within 120 calendar days of the Misoperation, develop one of the following: • A Corrective Action Plan (CAP) that includes: 1. Interim corrective actions (if any). 2. Final corrective or mitigating actions to reduce potential impacts to BES reliability. 3. A work timetable. • A declaration explaining why there is no need to develop a CAP. **R1.4.** A requirement that for all Misoperations for which the cause(s) was (were) not identified, the Registered Entity shall, within 120 calendar days of the Misoperation, develop one of the following: • An action plan that identifies: 1. Additional investigative actions and/or Protection System modifications.

		2. A work timetable. • A declaration that includes an explanation of why no further investigation or actions will be taken. A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented.
R1, Part 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	PRC-004-3 Requirement R1 replaces the Regional Reliability Organization with the Transmission Owner, Generator Owner, and Distribution Provider as the Responsible entity(s) for reviewing events to identify all Misoperations.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	PRC-004-3 Requirement R1 replaces the Regional Reliability Organization with the Transmission Owner, Generator Owner, and Distribution Provider as the Responsible entity(s) for reviewing events to identify all Misoperations. Rather than requiring ongoing updates and maintenance of the procedure, the Standard has specified the minimum elements that must be included in the procedure.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	PRC-004-3 Requirement R1 replaces the Regional Reliability Organization with the Transmission Owner, Generator Owner, and Distribution Provider as the Responsible entity(s) for reviewing events to identify all Misoperations. Accordingly, there is no need to distribute the procedures.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**

Standard: PRC-004-2 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperations or Comment**
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 specifies the Transmission Owner and Distribution Provider must have and implement a procedure that requires analysis and development of pans as appropriate.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 specifies the Generator Owner must have and implement a procedure that requires analysis and development of pans as appropriate.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include: [*Violation Risk Factor: High*] [*Time Horizon: Operations Assessment, Operations Planning*] **(parts omitted for brevity)**
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	PRC-004-3 Section 1.4 Additional Compliance Information specifies submitting Misoperation data on a quarterly basis using the format specified by the ERO. The format for data submission is based on the current TADS reporting template. PRC-004-3 Measures specifies documentation requirements with Evidence Retention of 6 years.	**1.4. Additional Compliance Information** **Periodic Data Submittal:** Within 60 calendar days following the end of the calendar quarter, each Transmission Owner, Generator Owner, or Distribution Provider that owns BES protection Systems will submit a quarterly report to its Regional Entity, identifying all Misoperations in accordance with Requirement R1using the format as specified by the ERO. Each Misoperation shall be updated on a quarterly basis until the CAP or action plan is reported complete. The Regional Entity will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for 1st Draft of PRC-004-3 – Protection System Misoperation Identification and Correction [Project 2010-05.1 Phase1]

Please **DO NOT** use this form to submit comments on the 1st draft of the standard for Protection System Misoperation Identification and Correction. Comments must be submitted by **July 9, 2011**. If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Background Information:

This project addresses two very important issues for NERC and the entire ERO enterprise - reliability and accountability.

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 as a “fill-in-the-blank” standard and did not approve or remand the standard since the regional procedures had not been submitted.

Since PRC-003-1 is not enforceable, there is no mandatory requirement for the Regional Entity procedures to support the requirements of PRC-004-2. This gap has been addressed in the draft standard by incorporating a requirement for quarterly reporting of Misoperations data, using a uniform template (provided as an Excel file).

Misoperation data, as currently collected and reported, is not usable to establish a consistent measure of Protection System performance. The SAR includes establishing a standard with uniform applicability, revising the definition of Misoperation, and clarifying reporting requirements.

The proposed requirement of the revised Reliability Standard PRC-004-3 would require that responsible entities establish and implement a procedure for reviewing all Faults and Protection System operations on the BES be to identify those that are BES Protection System Misoperations; and for each Misoperation, conduct an analysis to determine and address the cause(s) of the Misoperation.

This project also includes revising the existing definition of Misoperation to make it less ambiguous.

There are two WECC standards, PRC-003-STD-1 and PRC-004-WECC-1, related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where those standards will overlap with the Continent-wide standard, entities are expected to comply with the more stringent standard. Doing so will ensure compliance with the less stringent standard as well. There are no apparent conflicts between the proposed continent-wide standard and WECC regional standards that would lead to mutually exclusive compliance.

The reporting of Misoperations associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding has not been addressed in this standard due the complexity of the subject matter. NERC intends to address these areas through a separate project in the future.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The definition of 'Misoperation' has been revised. Do you agree with the proposed definition? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

2. In Requirement R1, the team is requiring the identification of all Misoperations. Do you agree that Requirement R1 is sufficient to identify Misoperations? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

3. Requirements R2, R3, and R4 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with the allotted times? If not, please provide specific reasons why not and alternative recommendations.

   ☐ Yes

   ☐ No

   Comments:

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

   ☐ Yes

   ☐ No

   Comments:

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

   ☐ Yes

   ☐ No

   Comments:

6. The team has included the “Quarterly Misoperations Reporting Data” table and template, and the supporting reference document. Do you have any specific suggestions for improvement?

   Comments:

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.

   Conflict:

   Comments:

8. 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.

   Regional Variance:

   Business Practice:

   Comments:

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

   Comments:

In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).

10. If you have any comments on the draft SAR, please provide them here.

    Comments:

Standards Announcement

Project 2010-05.1 Protection Systems Phase 1 (Misoperations)
Formal and Informal Comment Period Open June 10 – July 11, 2011

Now available at: http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

The Standards Committee has authorized posting a draft SAR for Phase 1 (Misoperations) of Project 2010-05, Protection Systems, along with an initial draft of PRC-004-3 Protection System Misoperation Identification and Correction, an Excel template to be used for quarterly reporting of misoperations data as called for in the Compliance section of the standard, and a reference document, which is an example to assist entities in completing the reporting template. A proposed implementation plan and several related documents have also been posted for reference, including clean copies of current versions of PRC-003-1, PRC-004-1a, and PRC-004-2, a white paper developed by the NERC System Protection and Control Subcommittee, a list of stakeholder-identified issues and FERC directives associated with the project, and a mapping of the requirements in the current standards to the proposed new requirement.

The SAR is posted for a 30-day informal comment period, and the standard is posted concurrently for a 30-day formal comment period. A single comment form is being used to collect both sets of comments, and the comment period will end at **8 p.m. Eastern on Monday, July 11, 2011.**

Instructions for Commenting

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Next Steps

The Standards Committee will appoint a drafting team from the nominations submitted during the nomination period that closed on June 3, 2011. The appointed team will consider all comments and make revisions to the draft standard to address issues identified by commenters. The team will submit its work for quality review. Following quality review, the team's consideration of comments will be posted, along with the revised standard, associated implementation plan, and supporting documents. The standard will then be posted for a 45-day formal comment period with an initial ballot conducted during the last 10 days of the comment period.

Background

This project addresses two very important issues for NERC and the entire ERO enterprise - reliability and accountability. A key element for BES reliability is the correct performance of Protection Systems. Identifying and correcting the causes of Misoperations should improve Protection System performance.

The scope of the work in this project includes the following:

- Revise the definition of Misoperation
- Combine PRC-003 and PRC-004
- Retire standard PRC-003.

In FERC Order No. 693 (dated March 16, 2007), the Commission identified PRC-003-1 as a "fill-in-the-blank" standard and did not approve or remand the standard since the regional procedures had not been submitted. Since PRC-003-1 is not enforceable, there is no mandatory requirement for the Regional Reliability Organization to develop procedures to support the requirements of PRC-004-2. This gap has been addressed in the draft standard by incorporating the details of what to investigate into new requirements and by adding a periodic data submittal for quarterly reporting of Misoperations data, using a uniform template (provided as an Excel file) in the compliance section of the proposed standard.

The second phase of this project will address revision of the standards associated with Special Protection Systems.

Additional information is available on the project page at http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

Individual or group. (52 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Question 1 (50 Responses)
Question 1 Comments (52 Responses)
Question 2 (47 Responses)
Question 2 Comments (52 Responses)
Question 3 (47 Responses)
Question 3 Comments (52 Responses)
Question 4 (35 Responses)
Question 4 Comments (52 Responses)
Question 5 (38 Responses)
Question 5 Comments (52 Responses)
Question 6 (33 Responses)
Question 6 Comments (52 Responses)
Question 7 (24 Responses)
Question 7 Comments (52 Responses)
Question 8 (2 Responses)
Question 8 Comments (52 Responses)
Question 9 (24 Responses)
Question 9 Comments (52 Responses)
Question 10 (0 Responses)
Question 10 Comments (52 Responses)

Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
The definition should be specific to Transmission or BES Misoperations
No
1.1.2 & 3 should be specific to BES Misoperations
Yes
No
Yes
Yes
Need to make it clear that if there are no misoperations no report is required.
Yes
You can't require the quarterly reporting of a non-event. reporting should only be required if there is an actual BES Misoperation, no null reports.
Group
Northeast Power Coordinating Council
Guy Zito
No
The new definitions only addressed “Slow Trip”. “Fast Trip” could cause misoperation as well. Suggest

that the new definition should include “Fast Trip”. In the definition of Slow Trip, the word “planned” should be replaced with designed. Not all faults have characteristics as planned, but fall within a Protection System’s designed capability. The “Unnecessary Trip-Other Than Fault” definition as written now would include trips during protection testing and commissioning. Suggest retaining phrase similar to one in current definition: “Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.” It can be said that Protection System Operations for settings that have been miscalculated or applied incorrectly are not misoperations because the hardware operated correctly. It has to be made clear that even though the hardware might operate correctly, for these situations it does not operate as desired. Terminology that has been used for these operations is “correct but undesired”. Suggested rewording for “Unnecessary Trip-Other Than Fault”: Any Protection System Operation for non-Fault conditions such as power swings, undervoltage, overexcitation, or loss of excitation for which the Protection System is not intended to operate. This would also include any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity, or correct but undesired operations because of settings that have been miscalculated or incorrectly applied.
Yes
This item refers to Part 1.1.
No
(This item actually refers to Parts 1.2, 1.3, and 1.4.) The Part 1.2 time interval of 90 days may not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages where they might be necessary. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although provision for this is made in Part 1.4, the language in Part 1.2 should be changed so as not to prejudge the appropriateness of an owner’s actions.
No
As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Many factors affect power system reliability, and an entity should have leeway to determine which is most important.
No
Measure M2 requires additional documentation with no additional value. Why would the “Quarterly Misoperations Reporting Data” table, in the format of the template provided with the standard, not be sufficient?
Yes
Although the inclusion of the Application Guidelines is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 (“Where studies have…) seems unduly prescriptive.
Individual
Greg Froehling
Green Country Energy
Yes
No
My concerns surround sub requirement 1.1 and 1.1.1. First concern is 1.1 the word detailed is too subjective of a term to be audited in my opinion. I would suggest replacing it with "step by step". Second concern is 1.1.1 "Document and review "all" BES Faults and BES Protection System operations." It does not address that protection system operations occur daily in a cycling combined cycle possibly other generation plants too. As an example the steam turbine is brought offline using the reverse power relay. That is a BES protection system operation. I would suggest language that

allows documentation of expected "normal operations" and secondly exempting those expected operations from the "document and review" requirement.
Yes
Just a comment for possible exceptions. When gathering data from manufacturers the 90day time frame can be aggressive. e.g. (GE) some language added to allow for information gathering time outside of the entities control would be helpful.
No
The term "written" keeps coming up and I feel it needs to be deleted since it has the connotation of a long hand "written" document and leaves no opportunity for an electronic format.
No
No
Group
Public Service Enterprise Group Company
John Seelke
Yes
The definition is acceptable provided the clarifications in the “Guidelines and Technical Basis” section of the draft is part of the standard.
Yes
Yes
Requirements R2, R3, and R4 do not exist. If R1-1.2, 1.3, and 1.4 are meant for comment, then the allotted times are agreeable with the following exception. As 1.4 is written it sounds like even after investigating for 90 days and not being able to find a cause for the misoperation, an action plan is needed to continue looking for the cause. The intent of the action plan in 1.4 (as indicated in the second and third full paragraphs on page 15) is not to conclusively determine a cause, but to take actions that may further a future investigation should another misoperation occur. The wording of 1.4 should be revised to reflect the true intent. We suggest changing 90 days in R1.2 to 180 days, and changing 120 days in R1.4 to 210 days (180 +30). In certain cases, root causes may not be able to be fully evaluated in 90 days because lines may need to be removed from service to do so, and clearances may not be granted within the 90-day window. By extending the time frame to 180 days, the time needed for removing lines from service for root cause determination will be sufficient in virtually all cases, thereby eliminating the burden for Corrective Action Plans and the associated requirements of such plans. The first sentence of Section 1.4 should also be changed to read “Within 60 days following June 30 and December 31,” and in Attachment 1 the title “Quarterly” should be changed to “Semi-Annual.” Other suggestions: Change the second bullet in R1.2 so that it directly refers to R1.4. Also, make R1.2 language “past’ tense to be consistent with R1.3 and R1.4.
No
Setting the VRF as HIGH seems to indicate there is no time to waste in finding and correcting the cause of the misoperation, yet 90 days are allowed currently to investigate, and another 30 days are allowed to develop a Corrective Action Plan, for which there is no timeframe given for completing other than to document a timeframe and abide by it. Because of this long timeframe in the standard as currently drafted, a VRF of MEDIUM is appropriate.
No
We recommend that R1.5, which is referenced in M6 and M7, be eliminated because the progress reporting of each CAP, including its completion, is sufficiently addressed in Section 1.4 (of the Compliance Monitoring Process section of the standard) which states “Each responsible entity will include the status of its Misoperation CAPS or action plans developed until these CAPs or action plans

are reported complete." We note that Attachment 1, which defines the format of these periodic reports, allows an entity to enter CAP progress data beginning at the bottom of page 3 with corrective actions taken, and continuing on page 4 where CAP target and actual completion dates are reported. Evidence supporting those periodic reports could be requested as needed, and if necessary, the retention of evidence supporting the reports can be addressed in Section 1.2 of the Compliance Monitoring Process. With the elimination of R1.5, M6 and M7 can also be eliminated.
Yes
See the previous comment in response to question 3 regarding semi-annual rather than quarterly reports. In addition, the current format of the Excel file can be improved to make it more "user-friendly." We recommend that the information in Row 3 be converted into Excel "comments" and placed in Row 2. This will eliminate a row from viewing and allow the user to scroll down and still have the valuable information from Row 3 available in Row 2 if needed. In addition, adjusting the font size may allow for more columns to be viewed on one screen.
Individual
Si Truc PHAN
Hydro-Quebec TransÉnergie
Yes
Yes
Yes
Yes
Yes
Yes
No
No
No comment
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP believes that that the NERC Glossary definition of Misoperation must coincide exactly with the one used by the ERO-Reliability Assessment and Performance Analysis (RAPA) Group. Although the differences are minor, the two processes need to seamlessly flow together so that data needs and reporting templates do not diverge.
No
There needs to be a tight correlation with the Misoperation cause codes already introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place.

Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up – with unique data requirements and reporting templates.
Yes
Ingleside Cogeneration believes that 90 days is generally enough to assess a Misoperation – or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The 120 day corrective action plan time frame is acceptable to us as well.
No
Ingleside Cogeneration LP does not believe that a Severe VSL is appropriate if a Protection System operation with an obvious cause is not captured in a summary listing (R1.1 and M2). We understand the need for a rigorous review process, but in many cases, a thorough evaluation is just not needed.
Yes
There needs to be a tight correlation with the Misoperation categories and cause codes introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place. Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up – with unique data requirements and reporting templates.
No
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
Yes
Yes
No
No
No
Individual
Bob R. Davis
Private Citizen
No

The definition of a Misoperation no longer includes an exclusion for maintenance activities. Is this intended? While I certainly agree that human erors can cause serious disturbances - for instance the Florida event in 2008 - these events also present lots of challenges to correct. Their can be labor issues, disciplinary issues, and a general problem of what CAP to take when the field person says "I knew better. I just screwed up." So, I wanted to know if the drafting team had explicitly considered this topic and chose to include it as a Misoperation going forward.
No
In R1.1.1, the drafting team calls for all BES faults and operations to be documented and reviewed. Why? Presumably, the drafting team is concerned that Misoperations can go undetected and that the opportunity to learn from - and avoid that SECOND Misoperation - would be lost. However, in the Guidelines and Technical Basis found on page 12 of 16, the drafting team proceeds to define certain protection system "failures" (my term) as not being a Misoperation. For instance, the failure of a redundant Protection System when another Protection System operates correctly or the failure of a communication scheme when TPL standards were not violated. Conceptually, this makes no sense. Either you are worried about undetected Misoperations or you are not. But you cannot have it both ways. Imho (in my honest opinion, so my grand kids tell me, you should write the investigation requirements like this. One must investigate to see if a Misoperation occurred when: a) the operation of any current interrupting device (i.e. breaker) by relay action for a fault not in its primary zone of protection, b) the oepration of any circuit interrupting device by relay action when no fault occurred, c) when equipment damage due to a fault condition occurs , but no Protection System operated. The wording can be improved, but I believe you can get the idea. If the drafting team believes it must have all operations analyzed, then it must remove the exemptions in the Guidelines and Technical Basis, as these are inconsistent with analyzing all operations for Misoperations.
No
See my comments on Question 9.
No
Yes
I thank the drafting team for their efforts to date and for the opportunity to comment. The job of a drafting team is not easy. My comments are as follows: 1) I just wanted to add what I thought the true Purpose of the standard is/should be: Misoperation analysis is a reactive tool – one waits for a Misoperation, then analyzes why it happened with the purpose of determining what, if any, changes need to be made to prevent another occurrence in the entity's system. Changes could be simple or complex, at one location or at many locations. Primarily, you are working to prevent a SECOND Misoperation. The SECOND misoperation could be either on existing system(s) or on future systems. I think it is important to note that it is the occurrence of the SECOND misoperation that is the true indicator of whether the efforts to prevent a Misoepration have been successful. A SECOND Misoperation indicates that it has not. 2) In R1, the drafting team calls for each entity to have a procedure. I am unclear on what benefit this provides, other than giving the auditors something to audit. Why not just call for an entity to do XYZ rather than say they must have a procedure that says they will do XYZ and they must follow the procedure. I see requiring a procedure as unnecessary documentation. Can the drafting team comment on why they asked for a procedure? 3) In R1.1, the drafting team calls for a "detailed" description. There is no measure for 'detailed". I believe the drafting team should seek to avoid such undefined terms. Shouldn't the standard just call for a procedure that includes the things listed in the standard? Or better yet, not call for a procedure at all, but just say you must do XYZ? 4) In the Background, it states that one goal of the standard is to collect data to establish a metric to measure Protection System performance. While I think this is a worthy goal in theory, I am skeptical about its usefulness in practice. Protection systems are an Art, not a science, and while most protection systems are made from the same building blocks, the application of them can vary wildly from utility to utility. Before requiring data collection - which would presumably cause a utility to get a NERC violation for failing to send in the data - I would be curious to know how this has worked in the regions that do, today, colelct this data. For instance, I

believe SERC collects this kind of data. Has this proven useful for developing a metric for SERC entities? If it has not, why not? Let's not repeat a mistake on a continent wide basis. 5) CAPs - the drafting team has written all kinds of rules for CAPs, including trying to hold the entity to a work timetable. What if the entity chooses to say it will take 100 years to fix so that they avoid the possibility of getting a violation for missing their timetable? I personally think CAPs should be eliminated from the standard as they are simply un-workable. You cannot know whether the CAP makes sense without evaluating them on a case-by-case basis. Consider that the CAP actions fall into three broad areas: a) Do nothing (for any of a boatlaod of reasons) b) Correct the issue at this one location c) Correct the issue at all locations Generally, c) is preferred, but their may be times when a) is the best solution, because fixing the issue may make things worse. So, instead, how about a performance standard, whereby an entity gets a violation if a Misoperation occurs a SECOND time. I'll be the first to admit that the devil is in the details, but at least in this case, we're getting at the true reason for the standard - preventing that SECOND occurrence. Ultimately, we don't care how they do it, as long as they do it.
I'm not in the industry anymore, but I think the SAR assumes things that are not truly agreed upon by the industry. My comments are as follows: Review all BES faults/operations - see my comments in Q9. I do not believe the industry is in agreement that all operations need to be reviewed. Presumably, one could review a sub-set and capture the vast majority of potential Misoperations. This would be a better use of resources. So, my complaint here is that the SAR should not tie the hands of the drafting team by requiring that all operations are reviewed unless it makes sense. CAPs - again, see my comments in Q9. I'm unconvinced that you need lots of rules for CAPs. I think a performance requirement would be a better way to go. My complaint here is that it is too prescriptive. Again, the hands of the drafting team should not be tied like this.
Group
Western Area Power Administration
Brandy A. Dunn
No
The previous “out” for outages which occur during on-site maintenance and testing is missing from the new definition. We would definitely like to see this added. We do like the “Guidelines and Technical Basis” section at the back of the standard which provides some clarification. Hopefully this section gets retained and we agree with most of what is stated, in particular it gives us an “out” for comm-aided protection which is not required by Planning Studies. Misop Category 4 – it is desirable in some cases to “overprotect” or intentionally miscoordinate based on exposure and risk. For example, we tend to allow our Zone 1 elements to cover 85% of our subtransmission lines even though it will miscoordinate with high side tapped transformer protection. This is done so that we will react quickly to the majority of faults which occur mainly on the line. The incidence of high side faults on the tapped transformers is low and we accept the risk of overtripping in those cases. Allowance should be made for entities to intentionally miscoordinate where risk and value make sense. Misop Category 5 – this should actually be strengthened to mention a trip which occurs for non-Fault conditions where the relay or protection system fails. Is this not a misoperation?
Yes
Yes
No
M2 calls for a list of faults, protection system operations,etc. Would be good to be able to just point to our outage database instead of having to create a separate list. We are creating a separate spreadsheet at this point. Six years for evidence retention seems kind of long. We would suggest 3 years or one audit period.
No

Yes
The SAR refers to WECC standards PRC-003-STD-1 and PRC-004-WECC-1. It talks about how those standards might overlap. It is our understanding that PRC-004-WECC-1 replaces PRC-003-STD-1 so we don’t understand what NERC is getting at. Only one of those standards should be active at any point in time.
Group
Westar Energy
Bo Jones
No
“Unnecessary Trip – Other than fault” is not clear if an impedance-based transmission line Protection System trip in response to an unstable (or stable) power swing is a misoperation. “Failure to trip” as described in the Application Guidelines should have the reference to “within the time normally expected” removed as this would be addressed in “Slow Trip”.
No
The requirement should be specific to BES Misoperations.
No
Requirements R1.2, R1.3, and R1.4 introduce time limits. The requirements need additional clarification on the timeframes. Are the timeframes from when the operation occurs or from when the operation is determined to be a Misoperation? Exemptions to the established timeframes should be available in cases of large scale events. R1.2 – remove the requirement to document causes that were ruled out, overly burdensome and unnecessary. Remove the reference or specifically define what constitutes a declaration. R1.4 – remove or refine, overly burdensome and unnecessary. R1.5 – remove, vague and unnecessary.
No
No
Data retention should coincide with the audit cycle.
Yes
Consistency between the Standard requirements and the ‘Quarterly Misoperations Reporting Data’ table and template must be ensured.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
The fifth category “Unnecessary Trip-Other Than Fault” definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, “… unrelated to on-site maintenance and testing activity”. The new definition only addressed “Slow Trip”. Many times, “Fast Trip” could cause misoperation as well. We suggest that the new definition should include “Fast Trip”.
Yes
By selecting “Yes”, we assume “R1” mentioned here is really “R1.1”.
No
(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in

the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
No
As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
No
Measure M2 requires additional documentation with no additional value. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
Yes
Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have…) seems unduly prescriptive.
Group
Hydro One
Sasa Maljukan
No
The fifth category "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, "… unrelated to on-site maintenance and testing activity".
Yes
No
(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
No
As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
No
Measure M2 requires additional documentation with no additional value. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
No
No
Yes

Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have…) seems unduly prescriptive. Also, we have concerns with the identified time lines in R1.2, R1.3 and R1.4. Is the intent of the requirement for the RE to initiate action within the specified time once the misoperation is identified? The identification of a misoperation may not occur for some time after the actual protection system operation as there can be a lag between an operation occurring and the analysis of that operation. Some misoperations may be obvious but some others not so much. We think that more clarity is needed here.
Individual
David Burke
Orange and Rockland Utilities, Inc.
No
The new definition only addressed "Slow Trip". Many times, "Fast Trip" could cause misoperation as well. We suggest that the new definition should include "Fast Trip".
Yes
By selecting "Yes", we assume "R1" mentioned here is really "R1.1".
Yes
By selecting "Yes", we assume "R2, R3, and R4" mentioned here are actually "R1.2, R1.3, and R1.4" due to there are no R2, R3, and R4 in this new version (3).
Yes
None
None
None
None
None
Group
Georgia Transmission Corporation
Greg Davis
No
1. Failure to operate as designed: a) The protection system failed to operate for a fault within the designated zone of protection. b) The protection system failed to protect a designated BES component from a system abnormallity as designed. 2. Operating external to design parameters: a) The protection system operated with no fault condition persent. b) The protection system interrupted power to a BES component with no system abnormallity present. - Slow Trip (as defined) is difficult to measure without "smart relays" or fault recorders or sequence of event recorders in every BES station. A high impedance fault will naturally cause slow clearing times and may indicate an out of zone trip when compared to a bolted fault.
No
R.1.1.2 is extraneous. If R1.1.1 is adhered to, all misoperations will be identified and documented.
Yes
Agreed in principle, however the question should be R1.2, R1.3 and R1.4. Not R2, R3, R4.
Yes
No
PRC-018-1 R5 DME data retention for RRO events is 3 years. 3 years should be adequate considering data is now available in spreadsheet format.
Yes

Spreadsheets make terrible flat databases. Is this spreadsheet wiped clean each quarter or do incomplete CAPs carry over to the next quarter? What is the procedure to have a field modified if the normal "pull down" selection is not adequate?
No
Yes
Will TADS be able to show the percentages of misoperations versus total number of operations?
Group
Tri-State Generation and Transmission Ass'n - System Protection
Bill Middaugh
No
There needs to be a continuation of the specific exclusion for operations that occur as a result of on-site maintenance or testing activity. It seems that the exclusion is intended to remain since there is no “Cause of Misoperation” associated with maintenance or testing. We are not certain how the “Guidelines and Technical Basis” will accompany the new definition in the “NERC Glossary of Terms,” but the last sentence in (1) of the Guidelines is not supported by the definition. We disagree that the failure of one high speed Protection System to operate when another does operate should not be classified as a Protection System Misoperation. There may be times when that philosophy is appropriate, but not usually. If the non-operating system can be shown to have simply not had time to operate, then that can be explained in the event report, but typically both high-speed Protection Systems should operate unless one is designed to have a delay. But if it has a delay it shouldn’t be classified as high-speed.
No
The term “detailed” is too vague and should be eliminated. See comments to the “Measures.”
Yes
The limits for those parts are acceptable (though, as we comment in 4. below, we believe the parts should be individual requirements).
No
The Requirement R1 should be split into several requirements with individual VRFs and VSLs. For example, the Measure associated with Requirement R1, Part 1.1 is primarily administrative in nature and should not have a “High” VRF.
No
Measure M2 (and possibly others) is a Requirement. It does not improve reliability, but only provides for additional record keeping for compliance documentation.
Yes
All columns that reference “TADS” should be removed. Protection engineers, who will be filing these reports, do not generally have access to the TADS information or filings. Much of the TADS information is not required quarterly so it may not even be available for submittal by the Protection staff. The Regional Entities can supply the TADS information after it is received by them.
No
None
None.
Yes
As stated earlier, we believe the requirements should be expanded to state what is required rather than putting requirements in the measures. At that point we would be in a better position to address our comments to the requirements. We believe that UVLS and SPS/RAS should be included in this standard and then PRC-012, Requirements R1.6, R1.7, and PRC-016 can be eliminated. If the standard is not changed to include UVLS and SPS, why is UVLS excluded but not UFLS? Corrective Action Plan is defined in the NERC Glossary of Terms. Requirement 1, Part 1.3 should not describe what should be included in the CAP.

None
Group
FirstEnergy
Sam Ciccone
No
The last bullet of the current definition includes the phrase “unrelated to on-site maintenance and testing activity”. We suggest this be retained in the proposed definition to alleviate any misunderstandings among the responsible entities.
No
1. We do not believe that 1.1.1 (Document and review all BES Faults and BES Protection System operations.) should apply to GO as written, even though R1 indicates it would. We realize that the Glossary definition of BES includes generation resources, but as 1.1.1 is written, it implies that it's referring to the transmission system. 2. Regarding the phrase “within its system" at the end of R1, we ask that this be clarified by changing the phrase to “within its area of ownership or control”. 3. We ask that the requirements to “have” and “implement” a misoperations procedure be separated. We suggest removing the word “implement” from R1 and creating a separate R2. Furthermore, see our answer to Question 4 regarding VRF.
No
Various testing or investigating recommendations may require BES equipment be taken out of service to accomplish the appropriate testing and investigation involved with relay misoperations. This testing may dictate what CAP are appropriate. The time limits stated do not provide any exceptions for equipment which cannot be taken out of service within the time limits identified for operational concerns or when these equipment outages are cancelled by operations based on system integrity concerns. There should be some exceptions for these instances. R1.2 prescribes 90 days to investigate the misoperation. Compliance section 1.4 prescribes 60 days following the end of each calendar quarter to provide periodic data submittal. This timing will create a situation where the last month of the reporting time period will not yet be due for completion of the original investigation. We suggest the compliance section 1.4 agree with the 90 day investigation period so that all original investigations are completed at the time of the data submittal.
No
We do not agree with a HIGH VRF for the sole requirement in the proposed standard. We believe that not having a procedure for handling misoperations is much less of a risk to reliability than the actual reporting of the misoperations. We suggest that having a procedure requirement be assigned a LOW VRF, and the requirement to implement be assigned a “MEDIUM” VRF. Since this standard pertains to after-the-fact reporting, there is no immediate risk to the BES and none of the requirements therefore warrant a HIGH VRF.
No
Measure M7 – Since M6 already requires evidence to show implementation of the CAP as required by R1 subpart 1.5, we do not see the need to have M7 and suggest it be removed.
Yes
We ask that it be clear within the standard (maybe a link in the standard) of where you can obtain this form used for quarterly updates.
No
Not aware of any at this time.
Regional Variance:
This standard should be coordinated with regional reporting requirements to avoid duplication of efforts. For instance, RFC has Mis-Operations reporting requirements (per procedure titled “Reporting, Review, and Analysis of Protection System and Under Voltage Load Shedding (UVLS) Misoperations”) for Protection systems AND UVLS system. Since this standard covers reporting of Protection system mis-operations, it should include a variance for the RFC region, or NERC should direct RFC to revise their reporting requirements to remove protection system misoperations to avoid redundancy.
Yes
1. R1 Subpart 1.5 – We would appreciate clarification on the following regarding what constitutes successful completion of the Corrective Action Plan: Given the scenario of a maintenance error that

caused the operation of a protection system, we understand that per this standard, if this misoperation is reported, and the error was corrected per the reported corrective action plan, then the entity is compliant with the standard even if the human error occurs again on a separately reported misoperation incident. Please confirm this understanding. 2. Applicability Section – The proposed standard excludes SPS, RAS, and UVLS systems. However, we do not see an exclusion for UFLS. The standard should clarify whether or not UFLS are applicable. 3. Effective Date - We believe that the proposed 3 month implementation of PRC-004-3 is much too short for an entity to be able to achieve auditable compliance because it may require changes to internal procedures and business unit awareness of the new standard. We suggest at least 6 months after regulatory approval.
Group
Pepco Holdings Inc Affiliates
David Thorne
No
The original definition excluded protective system operations related to on-site maintenance and testing activities. The new definition does not. A true measure of the performance of a protective system should not include protective system operations caused or initiated by human errors during on-site activities. These include such things as failure to pull appropriate test switches during testing, inadvertently keying a direct transfer trip channel, accidently shorting or bridging a terminal block during construction activities while landing secondary cables, etc. As such, we would propose amending Item 5 of the proposed misoperation definition as follows: 5. Unnecessary Trip – Other Than Fault – Any Protective System Operation for non-fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protective system is not intended to operate. Unintended Protective System Operations that occur during on-site maintenance, testing, construction, and/or commissioning activities are not considered Protective System Misoperations. (this qualification is consistent with the definition included with the proposed misoperation reporting spreadsheet and with the intent of the original definition) Also, the qualifying comments in the “Application Guidelines” section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a misoperation and what does no
No
Requirement R1 should be modified to read “Each Transmission Owner, Generation Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protective System Misoperations within its system.” The term BES was omitted from R1. We feel the term BES should appear in both R1, as well as R1.1.1, since this requirement is applicable only to protective systems associated with the BES.
No
The 90 day window to conduct an investigation and identify the cause of a protective system misoperation is not practical in many situations and unreasonable. Outage windows for transmission facilities are highly dependent on weather and system loading conditions and as such are usually relegated to only a relatively few months during the Spring and Fall. Also, during these mild weather / low load times any outage request submitted to investigate a protective system misoperation is competing with numerous other construction related outage requests being evaluated by the Transmission Operator for TPL infrastructure upgrades in addition to other facility maintenance outages. The Transmission Operator typically requires a minimum 30 day lead time for scheduling outages on BES facilities. Granting of these outages is the sole responsibility of the Transmission Operator, not the Transmission Owner. Canceling of the outage by the Transmission Operator may require the Transmission Owner to go through the 30 day re-submittal process. Denial of an outage request by the Transmission Operator could delay the misoperation investigation and force the Transmission Owner to be in non-compliance. An emergency outage could be declared to enable a misoperation investigation to take place, but depending on loading and system conditions, the facility forced outage could result in an increased reliability risk to the system, and/or the need to run expensive off cost generation. Declaration of an emergency outage should rarely be used, only for those instances of very high risk. In summary, it is not practical in many situations or reasonable to expect the Transmission Owner to be responsible to investigate the cause of a misoperation within 90

days when they have no control over the outage scheduling and approval process. As such, both the 90 and 120 day time frames should be removed entirely from the standard (i.e., structure the requirements similar to existing PRC-004-1 & PRC-004-2). Alternatively, but not recommended, would be to develop time frames only for those activities over which the Transmission Owner has full control. This second approach would of course require an extensive rewrite of Requirements R1.2, R1.3 and R1.4 and would in the end contribute little to improving the timeliness of investigations, since the majority of the time consumed in the investigation process is waiting for outages to be granted. For example, a requirement could be established that “within 45 days of the date of each identified misoperation launch an investigation into the cause and submit an outage request for any facility outages as necessary for diagnostic testing.” These tasks are within the Transmission Owners control. However, completion of the investigation can not be bounded since the outage process is indeterminate and out of the control of the Transmission Owner. Similarly, since the development of the corrective action plan is dependent on completing the investigation (which is outage dependent), development of the CAP cannot be bounded either. Because of this it is recommended that all time frames be removed.
No
Most of the VSL’s are related to the time frames with which the misoperation investigation is completed, or the corrective action plan developed. Both of these are completely dependent on the availability of outages to perform diagnostic testing to determine the cause of the misoperation. As described extensively in Question #3 the Transmission Owner cannot be held responsible to complete these tasks within a specified time frame when they have no control over the outage scheduling and approval process. Compliance should be judged on whether all BES events were reviewed, an investigation conducted and a corrective action plan developed and implemented. Not whether these activities were completed within some arbitrarily chosen time frame. Compliance could also be judged on the timeliness and completeness of the quarterly data submittal mentioned in section C1.4 of the standard.
No
The data retention provisions within the proposed standard seem reasonable. However, there are concerns with several of the Measures. M2 – This measure should be re-written to state the entity shall “have evidence showing the dates of occurrence of all BES faults, associated protective system operations, and identified misoperations.” The standard should not specify the format that this data should be in. Some companies retain this data in their internal database format, or write detailed reports for each operation (both correct and incorrect). Specifying that a dated list be provided is unnecessary and non productive when other means of supplying the required evidence is available. M4 & M5 - To avoid duplication of efforts and record keeping, the evidence required to satisfy these two measures should be included on the ERO spreadsheet. This way the review and feedback from the Compliance Monitor on the data supplied will be more timely than waiting for the next audit cycle, which may be years away. This would improve the overall objective of improving the thoroughness of the investigations and corrective action plans. Also, the ERO spreadsheet and this feedback from the Compliance Monitor could be used as evidence of compliance during a formal audit.
No
No
Yes
Section 4.2.2 should be revised to read “Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Voltage and Under Frequency load shedding programs, and Sudden Pressure Relays (SPR) are excluded from this standard.” There has been past confusion as to whether the misoperation of an underfrequency relay, which is part of a regional load shedding program, is reportable under this standard. Excluding UFLS programs eliminates this confusion. Adding SPR to the exclusions will also eliminate confusion. Also, as mentioned in Question #1 the qualifying comments in the “Application Guidelines” section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a misoperation and what does not. However, the remaining sections of the “Application

Guidelines" appear to be either tutorial, or background, in nature and should not be part of the standard itself. Compliance data submittal C1.4 requires a quarterly report (ERO spreadsheet) be submitted within 60 calendar days following the end of each calendar quarter. However, as was pointed out repeatedly, due to the difficulty in obtaining outages it is highly unlikely that many misoperation investigations could be completed, or corrective action plans developed / implemented, within 60 days after a quarter ends (particularly for those events which occur late in the quarter). For instance, suppose a misoperation occurs in June (second quarter). Data submittal will be required 60 days after the quarter ends (August 31). However, outages to conduct the necessary diagnostic testing will not be available until mid to late September. Therefore in an attempt to improve the percentage of reported events where investigations are complete and causes determined, we would suggest requiring the data submittal 90 days following the end of each quarter. This additional delay in data submittal will not impact the reliability of the BES, since any protective system misoperation contributing to a major system disturbance is already being thoroughly reviewed / investigated under EOP-004 Disturbance Reporting Requirements. Under Section C 1.4 Additional Compliance Information, there is a reporting requirement. This should be included as a specific requirement in Section B. If not included in Sec B, it could easily be missed by the applicable entity as a requirement.
Individual
Twila Hofer
PSE
Yes
Yes
Yes
Yes
Yes
Yes
We have created an MSAccess database to track all misoperation information starting in 2011. An export file is created in the format of the WECC spreadsheet to meet your requirements. We feel that the MSAccess database offers several advantages in terms of the ability to sort records in many ways, offering a historical view of misoperations that will span multiple quarters and years, and still offers all of the "pull down" choices related to definitions and codes.
No
Combining similar standards and clarifying definitions or requirements is always good. Thanks for the effort.
Individual
Joanna Luong-Tran
TransAlta
No
To add item 6. Unnecessary Trip – Other than Fault – any Protection System Operation for non-fault conditions such as current sensing device failure, voltage sensing device failure, DC/AC control circuit/device failure.
Yes
No

There are no requirements R2, R3 and R4 on PRC-004-3
Yes
Yes
1) The Standard title would be: Protection System Operation Analysis and Protection System Misoperation Identification and Correction 2) The Purpose of this standard would be: Analyze the causes of operation of BES Protection systems and identify and correct the causes of Misoperation of BES Protection Systems.
Group
PacifiCorp
Sandra Shaffer
No
The proposal for a revised definition of “Misoperation” in the NERC Glossary of Terms includes five conditions. This definition is insufficient in the absence of considering such conditions in conjunction with the additional illustrative information offered in the “Guidelines and Technical Basis” (the “Guidelines”) appended to the draft of PRC-004-3 for industry review and comment. PacifiCorp believes that the proposed revised definition of “Misoperation” should either be: (1) expanded to include additional technical information such as that included in the Guidelines; or (2) revised to expressly provide that the Guidelines, as appended to the standard, are incorporated by reference in the definition. The definition of “Misoperation,” if included in the NERC Glossary of Terms as presently proposed, is not sufficiently robust for the purpose of registered entities properly identifying and addressing all Protection System Misoperations within their respective systems.
Yes
Yes
No comments.
Yes
No comments.
No comments.
No comments.
PacifiCorp suggests that Section 4.2.2 (regarding applicability of facilities) be revised to state as follows: “Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs, and Under Voltage Load Shedding programs are excluded from this standard.” PacifiCorp believes that the same rationale for excluding UVLS programs from this proposed standard should apply for UFLS programs. If the Standards Drafting Team has a specific rationale for making UFLS programs subject to this standard, please provide an explanation as part of the revised standard circulated for the next formal comment and voting period. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
No comments.
Individual
Ed Davis
Entergy Services
No
The definition of Misoperation as proposed in the definition section of the standard needs more detail.

In particular, with regard to “Failure to Trip – During Fault”, Protection System communication aided schemes which are not essential to meet NERC Planning Standards should be excluded from the definition of Misoperation. An entity that voluntarily exceeds NERC requirements by applying communication aided schemes with more rigor than is required by standards should not be exposed to additional compliance consequences as a result of exceeding those standards. The revised misoperation definition should specifically include such exception in the actual standard definition and NERC Glossary. In particular, the definition of Misoperation should be changed as follows: Failure to Trip - During Fault - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. Protection System communication aided schemes which are not essential to meet NERC Planning Standards are excluded from this definition.
Yes
No
For Misoperation corrective action plans which could require out of budget cycle funding, significant project coordination with other groups or entities, and/or require major outage considerations, 120 calendar days is too aggressive to meet a corrective action plan development requirement which includes “final corrective or mitigating actions…..”. We suggest the timing for R1.3 and R1.4 be 120 days following the completion of R1.2. Therefore, we suggest the wording for R1.3 and R1.4 be revised to: 1.3 A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following: 1.4 A requirement that for all Misoperations for which the cause(s) was (were) not identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following:
No
A single high VRF is too broad to be applied for all elements and geographical areas of the electrical system. Also, lower and moderate VSL assignments should be included for the corrective action plan completion timeline requirements.
Yes
The present template does not contain enough cause options. Additional granularity is needed to identify misoperation trends and to provide better focus on potential areas of improvement. For example, selecting AC failure as a misoperation cause which was due to rodent damage, or a relay failure cause due to a leaky roof, doesn’t provide cause information which would be useful to determine whether we are experiencing actual equipment problems or some other unrelated problem. Also, add a “No Problem Found” cause, to address those rare evolving type scenarios which would challenge even the best relay(s) and schemes, and where we actually know what happened, but there is no reasonable corrective action to prevent it from reoccurring.
There are instances when an entity will justifiably need to defer a corrective action plan. The standard needs to include provisions to be able to adjust or defer corrective action plans if necessary.
Individual
Dan Hansen
GenOn Energy
No
In the numerous locations used in the definition, replace “Any” with “A” Definition should incorporate the following exclusions: 1. Misoperations from human intervention during maintenance activities 2. Failure of a relay control function or protective function not associated with protection of the BES or a BES element, i.e. a microprocessor relay serving multiple functions including, but not exclusively, BES Protection. 3. Misoperations resulting from the effects of a disaster upon the Protection System components, i.e. a hurricane, tornado, fire, or flood destroys a substation control house.
No

The intent is understood: to promote timely investigations and responses. However, the allotted times assumes that scheduling outages for investigation, testing, or maintenance are easy to obtain in every instance. 90 days is insufficient time for seasonal periods lasting five or six months or more.
No
VRFs are worst-case one-size fits all. The risk applied to a 500kV transmission line is the same applied to a radial connected 75 MW generating unit on a 138kV system. The risk applied to the implementation of a corrective action plan is the same applied to post correction record keeping.
No
Yes
The attempt to keep the Standard simple and straightforward is appreciated. In the Requirements section, please simply state the intended requirement and eliminate the repeated use of catch-all terms such as “any” and “all” which open the door to future unintended interpretations. In R1.1, a “detailed” description is arbitrary and subjective. Reword the statement as follows: “A description of the processes used to:” In R1.1.1, reword the requirement, “Identify and document Faults and Protection System operations.” Documenting “all BES Faults” covers the entire continent. In Section R1.3 and R1.4, it is suggested to replace “a work timetable” with “a projected schedule.”
Group
NextEra Energy, Inc.
Silvia Parada Mitchell
No
NextEra Energy suggests modifying “Unnecessary Trip - Other Than Fault” to: Any Protection System operation in the absence of a fault or for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.
Yes
Yes
(Refers to Requirements R1.2, R1.3 & R1.4)
No
NextEra Energy thinks there should be flexibility with Corrective Action Plans (CAPs) and action plans. CAPs and action plans will involve steps that are prepared at a time when all relevant information is not available. As such, there may be a need to modify the CAPs and action plans as additional information becomes available. (See proposed text for Requirement R1.3 and R1.4 in the response for question 9 below.)
Yes
If a misoperation has multiple events before a root cause can be determined, then there should be one line item with multiple events, not multiple misoperations.
Yes
The CAPs and action plans are living documents that should be revised as additional information is gained. Requirement 1.3 should be revised to read (highlighted section added): • A Corrective Action Plan (CAP) (which may be amended as appropriate) that includes: Requirement 1.4 should be revised to read (highlighted section added): • An action plan (which may be amended as appropriate) that identifies:
Individual

Scott Berry
Indina Municipal Power Agency
No
IMPA has serious concerns that the proposed definition of “Misoperation”, including the list of conditions in Draft #1 dated June 9, 2011 (page 12/16) is broad and far reaching and could potentially include equipment not currently defined as Protection System equipment. For example, (3) includes “Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect” could be interpreted to include high voltage circuit breakers – if a breaker operates (trips) slower than intended (for example in 20 cycles instead of the factory stated 5 cycles) then this could potentially be termed a “Misoperation”. By default this would expand the scope of PRC-005 to include additional equipment not currently covered in PRC-005. In addition the Misoperation Categories listed in the drop-down box for Misoperation Category on the Quarterly Misoperation Reporting Form are even less detailed and could be interpreted differently and broader than the proposed definitions themselves. In addition there seems to be an extraordinary amount of effort in PRC-004-3 to lay blame for an operation (now termed “Misoperation”) on operating/maintenance/engineering personnel leaving the reporting utility open for damages because of “errors”. Utilities have and always will use good faith efforts and follow prudent utility practices when operating their utility. The goal of any utility is to minimize outages/customer interruptions – with PRC-004-3 we are now opening ourselves up to fines for lack of compliance and potential lawsuits should personnel “miss” a setting. Additional causes listed include in the definitions tab on the spreadsheet include, for instance, under Communications failures, Telco errors resulting in the malperformance of communications over leased lines. Once a leased line leaves the utility’s premises they have NO control over that circuit – it is the property of the Telco. If a TELCO technician lifts a bridge clip at a CO on a protection circuit then the utility could potentially be held responsible for a Misoperation. IMPA had no objections with the current definition of Misoperation and feels the proposed definition should stay consistent with current definition.
No
In its current proposed format R1. requires that ALL operations have to be reviewed and documented for determination of a possible “Misoperation”. Examples given as a “Misoperation” in the spreadsheet included a failed secondary potential breaker (see 1. above – PRC-004-3 greatly expands the equipment utilities must now test on a regular basis). IMPA feels that R1 goes above and beyond a good faith effort to identify a true protection system misoperation. In addition the process of documenting and reporting requirements are onerous and time consuming and could potentially become costly in terms of the dollars required to prove an operation was not a misoperation and in terms of the manpower required to oversee this effort. The BES is a dynamic system that undergoes changes continuously - for a utility to have the ability to foresee all of these real-time changes, anticipate the effect that these changes will have on their protection systems and eliminate all misoperations is not possible with today’s technology.
No
The times as listed are aggressive, especially for smaller utilities that have facilities whose loss would have minimal impact on the BES. It may be more appropriate to break the time limits into different categories, such as operations (and Misoperations) that impact critical facilities versus those operations that impact facilities that are not critical to the BES. For instance the time limits listed should apply only to critical facilities. For non-critical facilities the times should be extended to 180 days from the date of a Misoperation to complete the investigation and 240 days to develop a plan or otherwise address the Misoperation.
No
IMPA believes that all the sub-requirements should have their own individual VSL and VRF (similar to BAL-006-2). When assigning VRFs and VSLs to the requirement and sub-requirements, the SDT needs to keep in mind the name of the standard is Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The title is NOT Analysis and Mitigation of Transmission and Generation Protection System Operations. The way the draft is currently written if one operation is missed and it is not documented and reviewed then an entity has violated a requirement with a high Violation Risk Factor and a severe Violation Severity Limit even if no misoperation has occurred.
No
In the previous two version of PRC-004, the data retention time was not six years. How does the SDT

plan on making the implementation to the six year data retention when the previous data retention time was 12 months or until your CAP was completed? IMPA believes the previous data retention time requirement should be used on this version of PRC-004.
Yes
IMPA does not agree with the proposed definition of “Misoperation” and feels that the selections under Misoperation Category are broad and far reaching and will result in the vast majority of operations being termed “Misoperation”. In addition the definitions listed in the Definition Tab under the Cause(s) of Misoperation include equipment not covered under other Reliability Standards, such as Telco errors. These Causes need to be reviewed and modified to include only equipment covered by other Reliability Standards.
no comment
no comment
Yes
A NERC Rapid Development Team (one industry stakeholder out of ten individuals) drafted the SAR and the first draft copy of PRC-004-3. IMPA believes SAR development in this manner is fine, but the first draft of a standard should not be written by the NERC Rapid Development Team. This new process should not compromise the current stakeholder process of writing reliability standards. By using the Rapid Development Team in the attempt to gain efficiency or speed, the risk of becoming inefficient and increasing drafting standard time is greater because problems will have to be address formally through comments and revisions instead of through the informal drafting work of the stakeholder’s standard drafting team. IMPA appreciates the effort of trying to make the standard easier to understand by the use of Application Guidelines, but we are concern that the Application Guidelines will become, by association, part of the requirements of the standard. Application Guidelines will be used by auditors as a draft of what a Compliance Program should include and that registered entities will be required to comply with the suggestions listed for Part 1.1 – Part 1.4 and Section C-1.4. For instance, it is stated that an investigation report generally includes the following information: 1) initial evidence, 2) probable or potential causes, 3) tests and studies, and 4) conclusions. Are utilities going to be required to have the supporting documentation required for each of these steps? For instance, as stated in the Application Guideline, initial evidence “…contains the sequence of events, relay targets, and a summary of Disturbance Monitoring Equipment (DME) records.” However not all registered entities to which this draft Standard would apply to are currently required to have sequence of events and/or DME’s. If this source of information is not available to them will they be penalized or forced to install this equipment thereby subjecting them to further Standards? In addition short circuit and coordination studies are mentioned as being included in report. These studies can be costly and time consuming – will utilities be required to provide these in a report for each operation in order to prove that it was not a “Misoperation”? Guidelines should be viewed as just that – a guideline and should not be viewed as what a utility should include in their Compliance Program. For this standard, it has about a page and a quarter of requirements and almost five pages of Application Guidelines to tell an entity how to be in compliant. The requirements should be written in a manner to stand by themselves without guidelines and allow an entity the option of determining the best method of being in compliance with the requirement.
no comments
Individual
John Bee on behalf of the Exelon Companies
Exelon
Yes
The definitions are fairly generic but there are additional qualifications in the Application Guidelines. See #3 Slow Trip definitions versus Application Guidelines # 3, this could lead to inconsistent applications. ComEd: Suggest including verbiage regarding human performance events. Is the intent of bullet #5, on page 3, to excluded human performance events as with the previous definition?
No
PECO: Similar to what Reliability First Corporation has created; PECO suggests that the five categories of misoperations should be expanded to provide examples of what would constitute a misoperation vs. a non-misoperation for each of the categories. Exelon Nuclear: SERC Regional Criteria procedure for "Analysis and Reporting of Transmission and Generation Protection System

Misoperations," currently includes guidance on misoperation categories and classifications and provides comprehensive examples of misoperation classifications. Such guidance has proved invaluable when determining if an event met the definition for reporting to the Region in accordance with PRC-004. It is strongly suggested that the NERC SDT provide similar guidance to registered entities to ensure timely and consistent reporting. ComEd: A formatting comment; the Requirement number formatting does not align with the questions in the comment form. Assuming question 2 referring to R1 items 1.1 – 1.1.3, question 3 is referring to Requirements R1.2, R1.3 and R1.4. TS&C: The requirement should not be to “have a procedure” The reliability objective should be to record, investigate and if required, develop corrective actions for mis operations. Suggest the Requirement read: R1. The Applicable Entity shall record, investigate and implement corrective action planning for all faults and misoperations. R1.1 Record all BES faults and Protections System operations. R1.2. Complete an investigation and implement immediate corrective actions within 30 days. R1.3. Report mis operations each quarter using the reporting template. R1.4. Complete a corrective action plan for each identified mis operation. Requirements 1.2, 1.3 and 1.4 should be removed and replaced by one requirement. See suggested R1 above. Corrective Action Planning, Performance Improvement, Root Cause Analysis and Investigations are all standard business practices with widely accepted protocols and methodologies. The details concerning the possible outcomes of a CAP should be removed The standard requirements should not try to anticipate the possible outcomes, “cause not identified” and subsequent actions, “interim actions, final actions, timetables etc.” Nor should the standard include a statement requiring an entity to state that there is “no need to develop a CAP” or that “no further investigation is required”.
Yes
PECO: Time limits are reasonable; however, the drafting team should consider requests for extensions based on extenuating circumstances, i.e. emergent work/storm related issues, etc., related to R1.2, R1.3, and R1.4. It is not clear what the deferral reference on page 15 of 16 of the Application Guidelines refers to. It appears to allude to a deferral process for CAPs but this is not specifically identified in R1.5 of the standard. ComEd: For R1.3, is there an intended limit on the work time table? Coordinating mitigating actions between customer premises or other entities can extend corrective plans significantly. Exelon Nuclear: Time limits are reasonable; however, the SDT should strongly consider a provision for those events where the root cause of a misoperation may be dependent on an external investigation (e.g., a relay may have to be examined by the manufacturer in an attempt to determine a defect). The timeline associated with forensics performed by an external company are outside the control of the registered entity.
No
ComEd: For R1 VSL, not all potential actions can be identified based on ability to obtain outages associated with an investigation and many times an investigation start leads to other paths. If an entity then creates generic all encompassing check list to meet the intent of R1, would they be held accountable to complete all the items listed when the cause was found at step 3 of 50 as an example. Exelon Nuclear: Suggest rewording the VSL to state that "… either identified the cause or listed the preliminary actions planned to identify the cause …" to address the concern that not all potential actions may be able to be identified within the required timeline.
Yes
ComEd: On Measurement M3 & M4 with regards to a dated documentation, do these have to be captured in a system outside of a standard business application for the purpose of locking a tracking date?
Yes
Column Q, “Is this a TADs reportable outage”, should have NA as an option with a footnote or some acknowledgement that generators do not report or participate in the TADs system. Exelon Nuclear: Column Q should have an "N/A" or and "unknown" field as a selectable option. GO/GOPs do not report or participate in the TADs system.
No
Yes
What are the reporting expectations when a Protection System misoperation occurs between entities

and the failure is with the one of the entities? Would the entity not responsible for the cause also report a misoperation as a means to show cooperation? In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
Exelon Nuclear: Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary. "XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Group
Southern Company Generation
Bill Shultz
No
The proposed definition is excessively lengthly. Items 1, 2, and 3 should be combined into one statement: Any failure of a Protection System to operate for a fault or non-fault condition as it is designed to operate. Items 4 & 5 should be combined into one statement: Any Protection System operation for a fault or non-fault condition when it was not designed to operate. Alternatively, all five statements could be replaced with this one statement: A misoperation is either the operation of a Protection System when it should not have operated or the failure of a Protection System to operate when it should have operated.
No
We believe that too many details are included in the existing Requirement R1. It is not necessary to be so specific on the documentation process. A high level requirement is much more appropriate. With so many details regarding the investigation compositional elements, valuable attention to resolving the operation/mis-operation is diverted to record keeping. Keep in mind that a large utility may have several relay operations per week, and requiring specific time tabling for each requirement with varying start dates for the magnitude of relay operations makes the proposed approach quite burdensome. It is not necessary to have a written relay operation investigation methodology in order to investigate all relay operation. Requiring a program document is not an essential component of reviewing operations and executing corrective action if they are needed. Please consider changing the existing lengthly requirement that, in our opinion, has far too many detailed requirements with the following three requirements which match the objectives of the current draft on page 5 of the PRC-004-3 draft standard dated 09 Jun 2011 (Draft #1). R1: Review all Protection System operations on the BES and identify those that are BES Protection System Misoperations. R2: Analyze BES Protection System Misoperations to determine the cause(s). R3: Where appropriate, implement Corrective Action Plans to address the cause(s) of the BES Protection System Misoperation. The requirements do not need to be any more complicated that these. The accompanying measures to match these requirements can be: M1: Documentation proving that all (BES Protection System) operations werer reviewed. M2: Documentation of analyses to determine cause(s) of the mis-operation. M3: Documentation of all Corrective Action Plans (problem resolution) resulting from misoperations. Revising the requirements to match the objectives listed provides an effective. simply stated standard for identifying and correcting Protection System misoperations.
No
There are no requirements R2, R3, and R4 in the 09 Jun 2011 Draft #1 posted in the "Standards Under Development" NERC web site. Responding to these actions as written in R1.2, R1,3, and R1.4 of the draft standard, we believe that specifying so many deadlines for individual tasks will make the identification, investigation, analysis process too cumbersome. The periodic reporting requirements to the regional entity requires continuing attention to these tasks and is sufficient to ensure their completion.

Yes
The VRF needs to be high as is specified in the draft. The magnitude of the components that make up the VSL matrix in the proposed draft #1 is indicative of the excessively prescriptive composition. The requirements, measures, and violation severity levels need to be simplified as described in the comment to question 2 above.
No
As noted above in the comment with Question 2, the Measures along with the Requirements should be phrased to establish the objectives only and not in the details of one possible way to accomplished the objectives. Regarding the data (evidence) retention, what is the basis for the six year retention requirement? The data retention period needs to be the time elapsed since the previous audit unless directed by a Compliance Enforcement Authority to retain specific evidence for longer periods as part of an investigation. The Additional Conpliance Information section (1.4) contains a requirement for the TO/GO/DP to report to the RE. This should be in the main requirement section of the standard. Also, to eliminate PRC-003, a requirement is needed for the RE to gather the region's records and report to NERC.
Yes
Eliminate the TADS columns Q, R, and S for generators as this code is meaningless for those entities.
Yes
1) In 4.2.2, point to PRC-016 for SPS Misoperations. 2) In suggesting to use the objectives listed (on page 5 of the 09 Jun 2011 draft standard) as the recommended requirements in the comments to Question 2 above, the removal of "faults" from the first objective was intentional. Generator Owners are not advised of "all faults" and have no way of knowing of all faults. Our experience has been that some Protection System will ultimately operate whenever a Protection System Misoperation occurs, therefore the suggested R1 was written excluding "all faults". 3) Another reason for eliminating all of the time frames suggested by R1 (R1.2, R1.3, and R1.4) relates to the 60 day reporting requirement to regions. A misoperation can occur on the last day of the quarter which must be reported 60 days later. The R1 subsections above time frames overlap the 60 days for a misoperation occurring late in the quarter. The simplified requirements suggested eliminate this problem. 4) We disagree with the statement made in item 3 of the Guidelines and Technical Basis section (page 12) of the draft standard. If the system did not perform as it was intended to (designed to), then it is a misoperation. 5) It is unclear what the phrase "situations that challenge a Protection System" means on page 13, Part 1.1 of the draft standard. 6) The exhaustive description of an investigation (page 13 Part 1.2 paragraph) should only be required where a definitive cause is not identified. For those cases where the cause has been determined, only the bottom line needs to be formally documented. 7) Will the Guidelines and Technical Basis section of the draft standard (p 12-16) become part of the standard? It is not referenced in Section F Associated Documents (p 11). 8) Will the Background section (A5) be retained with the standard? 9) Are revisions to Corrective Action Plans allowed to facilitate handling contingencies?
Group
Transmission Access Policy Study Group
Cynthia S. Bogorad
Yes

We understand that the draft standard was drafted by a “rapid development team” rather than by a stakeholder Standard Drafting Team. This new rapid development team process should not displace or compromise the stakeholder process. TAPS supports the goal of developing better standards more efficiently. If NERC and Regional staff draft a standard without the benefit of significant industry input, however, we could risk moving toward greater inefficiency and delay, because problems that could have been addressed informally in drafting will instead have to be addressed formally through comments and revisions. Instead, the rapid development team should develop only the SAR, with the drafting of the standard left to the Standard Drafting Team, advised by technical writers and attorneys as appropriate.
Group
SPP Reliability Standards Development Team
Jonathan Hayes
No
Would like to add either in this section or in the application guidelines a reference to trips prior to synchronization would not be reported. They would be investigated and corrected but not reported. We are concerned that the definition would lose clarity if the application guidelines are moved out of the standard. If this happens we would like to see some of the meat of the guidelines added to the definition.
No
Want to be clear that the wording in R1 and in section R1.1.2 refer to the BES and not all Misoperations. Would like to see BES included in R1 between address all BES protection system misoperations. Also would like BES added to Section 1.1.2 for clarity. We would ask that this requirement be broken up to address identification, corrective action, and reporting. This would give you greater flexibility to create different VRF and VSLs for each piece that is being addressed. We feel that making an administrative action, such as completing a report, a high on the VRFs and VSLs isn’t justified.
No
We don’t agree with placing a timeframe on the investigation of a misoperation. There is an inconsistency with section 1.2 of the application guidelines and section 1.2 of R1. One states that its 90 days from the identification of the misoperation and the other states from the date that the misoperation occurred. If it’s the case that the 90 days start from the occurrence of the misoperation we are concerned that putting a timeframe on the analysis would cause detriment analysis especially during system wide event I.E hurricane. Could cause hundreds of operations and would need a longer analysis timeframe for these. Could add a process by which the entity could file for extension during these extraordinary circumstances. Was the intent for the timeframes to start after the misoperation was identified or was the intent to start the clock after the operation occurs? In the question it should have read R1.2, 1.3, 1.4 rather than R2, R3, R4.
No
See comment in question two.
No
We would like to see in section M2 BES faults added here as well to clarify that we are talking about BES rather than any fault. Should data retention follow the audit cycle for each applicable entity? I.E. if your audit cycle was three years then it would be three years and if it was six years then it would be the six years mentioned.
Yes
Attaching the TADS reference to this template could cause a non reporting for instances in which other entities actually report the TADS information and not the Misoperation. There needs to be consistency with the excel sheet language and the standard itself. Under the definitions tab in the excel sheet the language isn’t consistent with the language in the standard itself.
No
Would like clarification on failures during the synchronization of a unit. Clear line to when the point of

misoperation could occur. Shouldn't under frequency load shed also be excluded to be addressed at a later date? Under the applicability section shouldn't the wording have been kept from the last posting that it would be distribution provider that owns a BES protection system. Under compliance section third line protection needs to be capitalized. On the same line shall submit a quarterly report. Need to insert, "quarterly report for the previous quarter".
Individual
Joe Petaski
Manitoba Hydro
No
Item 3 (Slow Trip) in the definition of 'Misoperation' should be clarified by replacing the word 'planned' with 'specified'.
No
R1 should be clarified by changing '... and address all Protection System Misoperations within its system' to '... and address all Protection System Misoperations within its BES'. While the standard only applies to Protection Systems for Facilities that are part of the BES as stated in the Applicability Section, R1.1.1 explicitly states 'BES Faults' and 'BES Protection System operations' making R1 read like it refers to all Protection Misoperations in the Registered Entities' entire system. R1.1.1 and M2 are too prescriptive and should not specify the process that a Registered Entity must follow to determine when a Protection System Misoperation has occurred. R1.1.1 and M2 should only require a process to identify a list of all Protection System Misoperations rather than a list of every single fault and BES protection system operations on the Registered Entity's system.
Yes
No
Manitoba Hydro suggests that the sub-requirements of R1 are split into separate requirements (eg. R1, R2, R3, etc.) or each of the sub-requirements are assigned a separate VSL. The current VSL matrix is unclear.
No
Manitoba Hydro suggests that the Evidence Retention period be 3 Calendar Years to align with the data retention required for audits. The standard drafting team has not provided justification for extending the Evidence Retention period to 6 Calendar Years and given that Misoperations will be reported quarterly, it is not clear why 6 Calendar Years of evidence would be required.
Yes
In Column M (Misoperation Category) of the spreadsheet, only 4 Misoperation types are provided for selection - Failure to Trip, Slow Trip, Unnecessary Trip - During Fault, and Unnecessary Trip - Other than Fault. To be consistent with the proposed definition, Failure to Trip should be replaced with Failure to Trip - During Fault, and Failure to Trip - Other than Fault.
Yes
A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the Protection System elements that are included in the BES according to provincial legislation and the NERC definition. This may impact the Protection System Misoperations that are reported. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of PRC-004-3 and the associated Misoperation reporting requirements may differ for Canadian entities and entities under FERC jurisdiction.
Individual
Keith Morisette
Tacoma Power
Yes
Yes, the proposed definition is reasonable, provided that protection system operations resulting from

maintenance, testing, or similar inadvertent activities are excluded, as is the case with the existing definition. Alternatively, the proposed definition is reasonable if under R1.3, “a declaration explaining why there is no need to develop a CAP” is acceptable.
Yes
None
No
The Guidelines and Technical Basis section asserts that the 90 and 120 day timeframes “provide sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes.” For some responsible entities, this period arguably could approach 6 months (180 days). Exacerbating this issue is the fact that the VSL increases rapidly after the 90 and 120 day timeframes are exceeded. While identification, analysis, and correction of protection system mis-operations is important to reliability of the BES, the responsible entity should be granted greater latitude to triage investigations based upon the perceived severity of the nature of the mis-operation with respect to other operational constraints. Not all mis-operations are equal in potential impact. Investigating a mis-operation should not degrade system reliability in the name of compliance, and the 90 and 120 day timeframes may result in undue hurried response for some, less critical mis-operations.
No
An automatic VSL of severe should not be assigned by failure to review one event. A VSL structure similar to draft 4 of PRC-005-2 is more reasonable. It seems reasonable that an entity should be penalized less severely if a lower percentage (1) of BES faults and BES Protection System operations have been documented and reviewed, (2) of misoperations have been identified and documented, or (3) of misoperations have been investigated and addressed. Part of the concern is that an entity may be heavily penalized for failing to identify a misoperation, based upon a later finding or a technicality, even if the entity has performed due diligence. Such a later finding may place an entity in a Severe VSL category, and a fear of such a scenario may cause an entity to devote an unreasonable amount of resources to develop or implement its procedure per this draft standard, particularly for arguably less severe misoperations.
No
The distinction between M6 and M7 is unclear.
None
None
No more stringent regional variance should be applied for WECC.
The word ‘detailed’ should be removed from R1.1. Under R1.3, replace ‘Interim corrective actions’ with ‘Interim corrective or mitigating actions.’
None
Individual
Kirit Shah
Ameren
No
Please 1) show the present Misoperation definition so that entities can see how much SDT is proposing to change it. The entire 3rd bullet item (excluding on-site maintenance caused) of the existing definition needs to be retained in your proposed definition items 2 and 5; 2) clarify in item 3 ‘Slow Trip’ by adding ‘slower than required to meet TPL requirements’ as the SPCS intended; 3) explain in the Background section that “a Protection System” is an element’s protection in its entirety (e.g. for a transmission line, it would typically consist of both the primary and secondary protection designed to protect the line) and provide such an example; and, 4) remove ‘power swings’ from items 2 and 5 ‘Other Than Fault’ examples because it is pre-mature to include until after protective relay response during power swings is addressed in Phase 3 of Project 2010-13.
No
We assume you mean R1 and R1.1 here. Please 1) review and incorporate the Project 2009-17 interpretations that have been correctly incorporated in PRC-004-1a; the SDT should recognize PRC-004-1a in the Background section to provide correct history and continuity. 2) reword R1 to state:

“Each … and address its Protection System Misoperations.” This removes ‘all’ because though we strive to find all it is impractical to guarantee all were found. The TO, GO, DP is responsible for the Protection Systems they each own, thus use ‘its’ and remove ‘within its system’ for clarity of responsibility. 3) reword R1.1.1 to replace ‘all’ with ‘its’ for the same reasons as 2) above. 4) reword R1.1.3 to insert ‘identified’ before Misoperation.
No
We don’t see R2, R3, and R4 in the posted document; We assume the SDT mean R1.2, 1.3 and 1.4. 1)From our perspective, the SDT rationale for R1 is flawed. Using the posted TADS 2008 and 2009 reports, Failed Protection System Equipment is only responsible for 1.1% of the hours of AC Circuit Sustained Outages and ranks as the 9th Cause Code. Considering the large number of sustained outages, even larger number of momentary outages, and huge number of non-outage hours in which the Protection System correctly restrained, the Protection System is extremely reliable across a wide range of conditions and numerous challenges. We agree that Misoperations should be investigated and corrective actions taken if a reasonable cause is found, but the importance of this issue is being overstated. 2)In R1.2, please rReplace ’90 calendar days’ with ‘six calendar months’ to allow sufficient investigation time in non-peaking periods because BES equipment outages are needed for a fair number of investigations. 3)In R1., please restate as “ A requirement that for each Misoperation for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days of the cause being identified per R1.2, develop one of the following …” because the Corrective Action Plan cannot be developed until after the cause is identified. 4)R1.4 also needs to be 120 days subsequent to initial field investigation of R1.2, similar to R1.3, and replace ‘all’ with ‘each’.
No
1) R1 VRF should be Low because the risk to BES reliability from one BES Fault or one BES Protection System operation not being documented and reviewed is very minute. The SDT itself alleges that up until now there are not even required Regional Entity procedures to support PRC-004-2, which would lead to numerous omissions in such regions. Operating as such under the proposed PRC-004-3 would lead to numerous High VRF and Severe VSL violations. One would expect a very unreliable BES over the past 4 years; however, the BES has been extremely reliable in this time frame. 2) The VSL need to be completely restated to recognize that a higher volume and BES voltage level >200kV Misoperations deserve a higher severity level, but fixing the number of days an entity is late at 90 days. For example, if an entity is unaware of one Misoperation on the <200kV, they’ll end up missing all the deadlines; this belongs in the Lower VSL category. But one omitted Misoperation on the >200kV belongs in Moderate VSL. We propose <200kV omission quantities of 1, 2 to 4, 5 to 10, and >10 Misoperations in the Low, Moderate, High, and Severe VSL respectively. We propose >200kV omission quantities of 1, 2 to 4, and >4 Misoperations in the Moderate, High, and Severe VSL respectively. Similarly missing R1 deadlines by >90 days for identified Misoperations of the same number (1, 2 to 4, etc.) and voltage level would fall into our proposed VSL categories.
No
1) We believe that the Evidence Retention back to the most recent Compliance Audit is sufficient. The Regional Entity has access to all evidence during the Compliance Audit so it need not be retained after that. TO, GO, and DP are reporting Misoperations quarterly to the Regional Entity, so sufficient ongoing monitoring can occur. 2) Many measures require ‘dated written lists’. We presently use an outage tracking database, which includes our correct operations and Misoperations. Are you requiring us to revise this software so that it automatically tracks date and time of entry of each pertinent item of this standard? Please provide some guidance or point us to what NERC accepts as an equivalent to a ‘dated written list’. 3) In M, please remove ‘each’ as this in an extra word. There seems to be a few other grammatical errors in this sentence.
Yes
1) For Time Zone use Prevailing Time, e.g. CPT for Central Prevailing Time because that’s what EMS systems provide. The switch to Daylight Savings time is simultaneous. 2) Require GO to use their GSU high side voltage for Facility Voltage, rather than the generator voltage which will always be <100 as the Facility Voltage.
1) The industry is in the process of adopting the RAPA template. We disagree with the Background statement that Misoperation data, as currently collected and reported is not usable. It seems to us

that plenty of Misoperation statistics have been issued, though they may be misleading. 2) We have been through multiple audits and regional reviews of our reported Misoperations, and strongly disagree with the Background statement that the present PRC003 / 4 status is a 'reliability gap'. 3) Are the "Guidelines and Technical Basis" part of the standard? What is their purpose? They do provide a reasonable engineering practice explanation in several cases. In item (3), please strike "or by coordination requirements with other Protection Systems." 4) The evidentiary requirements of this proposed standard greatly exceed those of the present standard, and rigid timelines are required. Entities need more time to make software changes, increase and train staff, and implement processes. Please change implementation to 'first day... 6 months after applicable regulatory approval'. 5) The standard and implementation plan should also exclude UFLS. Add 'Underfrequency Load Shedding' in 4.2.2.
Group
MRO's NERC Standards Review Forum
Carol Gerou
Yes
No
This requirement is overly prescriptive and unnecessary. The requirements (and its parts) should not prescribe how entities should comply, but address the "what" is to be accomplished within this requirement. NERC Reliability Standards should specify simple actions such as: 1) that the applicable entities should have a procedure for identifying all BES protection system misoperation on BES protection systems installed for detecting faults on BES elements, 2) implement corrective actions for identified systemic causes of BES protection system misoperations, 3) document those actions, and 4) report all BES misoperations to their regional entity on a quarterly basis. This is a better way to meet the goal to require the identification of all BES protection systems installed for detecting faults on BES elements. Simply have a plan, implement the plan when warranted, document what the entity accomplished and report quarterly to the applicable Region. The misoperation report could also be used by NERC and the applicable Region for trending of misoperations. It is recommended that the SDT align this project with the NERC Functional model. The reference to its system implies operations when it's more like the equipment it owns, please clarify. R1 also uses the word "all" with Protection System Misoperations. Since the SDT has defined 5 different attributes of what a Misoperation is, this would require every function of a relay to have 5 areas that "identify and address" the associated Misoperation. If an entity's relay has 15 functions associated with it, they will need to identify up to 75 ways of identifying and addressing the Misoperation. Note that Protection System is clearly defined and has 5 components to it. So the 75 ways to identify and address the Misoperation will also need 4 more (not five since relays are used as the example). Recommend that the SDT rewrite R1 to read: Each TO, GO, and DP shall have and implement when required, a procedure to identify and address the Misoperation of a BES Protection System within its metered boundaries. Recommend that the SDT add a requirement 2 that fulfils the section 1.4 additional compliance information concerning quarterly reporting. Requirement 1.1.1 should be for BES Protection System misoperations not all operations. The use of the word "all" BES Protection System operations seems unreasonable and un-necessary. Exceptions need to be allowed e.g., acts of god, storms, etc. This requirement is overly burdensome for those individuals involved in restoration. (Certain relays lose information once they are reset.) The NSRF recommends that that this requirement be removed altogether unless further clarified.
No
We agree with the time tables/time lines if a bullet is added to allow the Regional Entity to grant the registered entity an extension beyond the 90 days within R1.2 and beyond the 120 days within R1.3 and R1.4.
No
The VSLs are incorrect. All documentation time frame references should be deleted. If they are retained the VRF for R1 should be dropped to lower as the requirement is now administrative documentation. Documentation does not affect the electrical state or capability of the bulk electric system. The non documentation items under the severe VSLs can be modified to fit the moderate, high, and severe categories as follows: Moderate: The responsible entity did not identify all protection system misoperations High: The responsible entity did not investigate all identified protection system

misoperations Severe: The responsible entity did not have a procedure to address protection system misoperations OR the responsible entity did not implement a plan to correct any misoperations.
No
The measures are incorrect and must be changed to match the modified requirements. However, the measures are reasonable and could be translated into requirements R1 – R6 or R1 – R7 with corresponding measures. The data retention is incorrect. The data retention should state that data should be retained back to the last audit period. If not, the drafting team should provide the reliability reasoning why an entity with an audit cycle faster than six years would need to retain data past its last audit cycle. In 1.2 Evidence Retention, the "and Measures M1, M2, M3, M4, M5, M6, and M7" reference should be deleted.
Yes
This should be a requirement.
Yes
Where does PRC-009 (new PRC-006) & PRC-020 overlap or are they in conflict with this standard?
Yes
Clearly exclude power plant trips when they aren't part of the BES as misoperations. Trips can occur easily during synchronization and may not be a reliability problem. There are many mechanical issues related to a power plant that may result in an electrical synchronization trip. It's best to avoid inadvertently requiring unnecessary work that won't benefit reliability by clearly excluding plants that are not connected to the BES or plants in the process of synchronizing to the BES. Non-BES plants should all be excluded. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
Individual
Brian Evans-Mongeon
Utility Services, Inc.
No
Utility Services disagrees with the addition of incorrect settings to the definition of a Misoperation (Cause Code in Table 2 of the White Paper). Misoperations imply that there was an action or inaction based upon the equipment not performing. It is our view that incorrect settings are a maintenance and testing function, not a misoperation. Utility Services is NOT suggesting that we ignore incorrect settings of these devices. I believe that incorrect settings should be dealt with in the PRC-005 standard instead. As a part of regular maintenance and or testing, the settings should be validated and affirmed by the entity. A misoperation is when a device fails to act or acts inappropriately. Finding out at the time of the misoperation that the settings are incorrect are not the right time to determine this. The better standard of reliability for these devices is to do it before they misoperate. If the M&T routines are validating the settings on a regular basis, then the discovery/re-correction will actually benefit reliability because they will be corrected prior to any so-called misoperation.
No
Please refer to our response to Question 1.
While we understand the need to move the Standards Development process on a faster pace, aka Rapid Development process; Utility Services feels that the RDp should not have the initial standard language drafted by RDp group. The SDT should be the group to draft the initial requirements. As outlined in the ROP, industry should be leading this effort.
Individual

Thad Ness
American Electric Power
No
It would appear that the proposed definition is overly broad, when compared to the application guidelines specified on page 12. For example, going strictly by the criteria on page 3, one might unnecessarily report a misoperation when it would not be considered such according to the guidelines. Employee action, during on-site maintenance and testing or commissioning activities, that directly initiates an unintentional operation should not be included in this category. However, for example, if an employee leaves trip test switches or cut-off switches in an inappropriate position following maintenance and testing or commissioning activities and a system fault or condition causes a misoperation, this would be counted as a misoperation.
No
We are confused by the numbering of the requirements in this question versus the numbering within the proposed standard. In addition, rather than developing additional sub-requirements and sub-sub-requirements which make it difficult to track compliance, we suggest discrete requirements which stand on their own. Requirement R1 is not sufficient, because there are additional considerations set forth in the Standard's "Guidelines and Technical Basis section" regarding the identification of misoperations. Requirement R1 should include a clear reference to the guidelines to lessen the possibility of confusion by an Entity or auditor. 1.1.3 appears redundant with 1.2, as operations must be investigated in order to identify whether or not a misoperation has occurred. In addition, more detail is needed as to the exact intention of the word "address".
No
There is no R2, R3, and R4 in the current draft of the standard. Also, the process needs to accommodate for the later identification of a misoperation after new information is obtained. Some investigations might take a month after an event occurs before that event could or would be declared a misoperation.
Yes
Though we agree overall with the VRFs, VSLs, and Time Horizons specified, the table seems more complex than necessary due to the number of "or" clauses involved. Should the sub-requirements perhaps stand on their own as individual requirements?
No
Within M4 and M5, it is not clear what the meaning or intent is of "dated written declaration", or what it would constitute.
No
AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, however, the definitions and reporting requirements for this standard would potentially be quite different from those required an RTO. This would not only produce duplication of efforts, but would also result in conflicting metrics.
We see no need for regional variances, whether for WECC or any other region.
Why is it necessary to have PRC-004 along with both PRC-006 and PRC-016? It is not clear why these cannot also be addressed in this revision process, as for AEP, it would seem to be a natural extension of these responsibilities. We suggest there should there be an explicit requirement regarding reporting, rather than providing this detail within the Compliance section. It is not clear how much flexibility, if any, there is in completing investigative work in a timetable as required by R 1.5. For example, due to outages or required maintenance activities, one might not be able to meet the date as set within the timetable, which would require a new proposed completion date. If one were to be held to the standard "literally", is it even allowable to complete the work early? Though the application guide seems to partially address allowing changes to the CAP, the standard should be more explicit in doing so.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC

No
The definition of Unnecessary Trip – During Fault should be changed to “Any Protection System operation that causes a circuit breaker/switcher to trip for a Fault not within the zone it is designed to protect.” The definition for Unnecessary Trip – Other Than Fault should be changed to “Any Protection System operation that causes a circuit breaker/switcher to trip for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.”
Yes
No
What about wide scale events such as the 2003 blackout? There does not appear to be an exception. ATC suggests that a provision be made to allow for declaration of an extension of the timelines identified in requirements R1.2, R1.3 and R1.4 in the case of a wide scale system event (NERC event categories 4 or 5).
No
ATC is concerned that the measures defined in M2, M3 and M5 leave out the possibility of using a database to capture the data. Please replace the term “dated written” in the measures section with “dated records”. This change allows for records stored in databases, generated from manufacturer programs as well as for written records.
Yes
In the supporting document “SPCS Input on Uniform Misoperations Reporting”: The Misoperations Categories include Slow trip (i.e., slower than required to meet TPL requirements). The parenthetical should be removed. Using the criteria of being slower than TPL standards, could be used as a loop hole. The Cause Code Description for As-left personnel error should be improved by adding a description to make it clear that human error due to ongoing testing is not included. ATC believes the intent is to include only those items when the technician has left the substation in an unwanted state.
Individual
Armin Klusman
CenterPoint Energy
No
The proposed revision to the definition of Misoperation includes conditions that are found in the Guidelines and Technical Basis in PRC-004-3, but not in the definition itself. CenterPoint Energy recommends that the conditions be included in the formal definition, instead of in a separate document. Should this recommendation not be accepted, as an alternative, the following statement should be added to each of the five items in the definition of Misoperation: “For specific conditions, refer to the Guidelines and Technical Basis in PRC-004-3 reliability standard.”

CenterPoint Energy recommends that Under Frequency Load Shedding programs be excluded from this standard. In the Applicability section of PRC-004-3, 4.2.2 should be written as follows: "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs (UFLS), and Under Voltage Load Shedding programs (UVLS) are excluded from this standard."
Individual
Steve Boutilier
BGE
No
Item #5 Unnecessary Trip – Other than Fault The misoperation definition included in the misoperation reporting template includes the caveat "an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable misoperation. This should be carried through the definition as well.
Yes
No comment.
No
R1.2 through R1.4 require the registered entity to complete various phases of a misoperation investigation by specific times. In general the times are generous enough to comply with, but the fact is many investigations require transmission facility outages that must be approved by the Transmission Operator, and these may not be granted. To meet the timeline set forth in the Requirements the Registered Entity may have to declare an emergency outage and accrue the expense of running off cost generation. While this requirement is seemingly reasonable, it unreasonably holds compliance by the Registered Entity hostage to the entities who have no "skin in the game".
No
The VSL 's are tied to the timetables set out in Requirements R1.2 through R1.4. As stated before, this unreasonably holds the registered entity hostage to the whims of a Transmission Operator or other entity who at best may have "no skin in the game" and at worst may have competing priorities…
No
M2. Through M5 requires "written lists, written investigation reports, written declarations, and written action plans…." The intent here should simply be all protection system operations, with auditable investigations reports, and clearly documented action plans. In a modern world these can be accomplished in many ways… The use of the term "written" is archaic….
Yes
The Application Guidelines need to be incorporated into the standard or specifically called out as a binding attachment to the standard.
No
No comment.
No comment.
No
No comment.
No comment.
Group
Southern Company
Antonio Grayson
No
The definition is acceptable; however, the following recommendations are provided to clarify the Guidelines and Technical Basis for the definition. Failure to Trip - During Fault: The reference to the time in which a Protection System is normally expected to operate introduces aspects of a slow trip into the discussion of failure to trip. To avoid confusion between failure to trip and slow trip, the

second sentence should be revised as follows: “If a fault or abnormal condition is cleared by at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation.” Slow Trip: The TPL standards require that the system is designed to meet performance requirements specified in TPL-001 through TPL-004, but does not require any specific remedy to assure that the requirements are met. Suggest referring to high-speed performance in the context of meeting the performance requirements in place of high-speed performance required by the TPL standards. The sentence should be revised as follows: “Delayed fault clearing caused by a failure of an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.” Unnecessary Trip - During Fault: Clarify that while operation of the backup system is not a misoperation, that failure of the protection for the adjacent zone is a misoperation. The Note should be revised as follows: “Operation of properly coordinated backup Protection System relays to clear the fault in an adjacent zone is not a Misoperation of that backup system if the protection for the adjacent zone fails to clear the fault within the specified time. However, the failure of the Protection System for the adjacent zone is a Misoperation.” Unnecessary Trip - Other Than Fault: The description for this part of the definition lacks clarity as to whether operation of an impedance-based transmission line Protection System in response to a power swing is a Misoperation. The description should be modified to provide clarity on this issue.
Yes
No
The 90 day and 120 day periods are acceptable; however, the start of the 90 day and 120 day periods requires clarification that time is measured from the “date of occurrence of each identified Misoperation.”
Not Applicable
Yes
Although we feel that tie back to TADS reporting will not accomplish the needed data unless TADS is modified to include 100-kV and above and generation facilities. Unless this is done, The tie back to TADS should be eliminated, if implemented, we would suggest the following modification: The recommendation is to state the actual range of TADS data collected. Proposed text – A review of the Transmission Availability Data System (TADS) data (20XX to 20XX) reveals that the fourth ranked initiating cause of BES outages not related to weather is “Failed Protection System Equipment.”
Individual
Eric Salsbury
Consumers Energy
No
This definition is much better than the current definition. However, the Unnecessary Trip - Other Than Fault should specifically exclude operations during on-site activities.
No
Suggest removing the term "all" in R1 and R1.1.1 as the Standard should focus only on Misoperations and not evaluation of all operations.
No
The time limits should be from the date of identification of a Misoperation and not the date of the Misoperation. This will allow for the time required to gather information from the field to determine if a Misoperation has actually occurred.

Yes
The Misoperation Category descriptions in the reporting template should match the wording of the proposed Misoperation definition as closely as possible.
Yes
1) The reporting template describes several typesof events that are "not reportable Misoperations". These types of events should also be specifically excluded in the standard, especially operations that occur during on-site activities. 2) The Effective Dates, listed in the Implementation Plan, are confusing as written. We suggest "first day of the first calendar quarter, at least 3 months after..." 3) Section 4.2.1 of the Applicability indicates the Standard is applicable to "Protection Systems". Since Protection System is capitalized, this indicates it is defined in the NERC Glossary. Is the intent of this standard to be inclusive of all protection system components (relays, cts, vt, dc circuits, and station batteries)? 4) In M2 remove "written lists". We are suggesting that no reference be made to lists.
Group
Electric Market Policy
Connie Lowe
No
Problems with 3. Slow Trip Use of term “slower” in the definition (Page 3 of 16) and “delayed” in the Application Guidelines (Page 12 of 16) is vague. “Slower” seems to indicate an unintentional time period before tripping while “Delayed” implies an intentional time period before tripping. Slow trip definition introduces the term “planned” which adds confusion. Reference to TPL standards implies the need for more and new System Studies. Must these studies be performed and documented prior to installation? What is requirement for keeping these studies current? NERC Glossary definition of Misoperation makes reference to a failure to operate within a specified time for an abnormal condition. There is no mention of “Slow” trip for a non-fault condition in the proposed definition. Only those terms that are in the NERC Glossary should be capitalized. Suggest wording changes as follows 1. Failure to trip - during Fault - Any failure of a Protection System to operate for a Fault within the zone it is intended to protect. 2. Failure to trip - other than Fault - Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate. 3. Slow trip – during Fault - Any Protection System operation that is slower than designed for a Fault within the zone it is intended to protect. 4. Slow trip – other than Fault - Any Protection System operation that is slower than designed for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which it is intended to operate. 5. Unnecessary trip - during Fault - Any Protection System operation for a Fault not within the zone it is intended to protect. 6. Unnecessary trip - other than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate including trips occurring when no disturbance is present. Excludes on-site maintenance and testing.
Yes
Dominion suggests R1 to read “Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protection System Misoperations within its system.” While the purpose statement indicates that is the intent of the standard, we believe the inclusion of BES in the first sentence of R1 will avoid questions as to whether this standard applies to ALL Protection System Misoperations (including those that are not designed to protect the BES). Recommend changing (R.1.1.1) to state “Document and review all BES Faults and BES Element operations. (R1.) Lists in the requirement that entities must identify and address all Protection System Misoperations. To do this you must either have a Fault or Element to operate to initiate the process. Having the Violation Risk Factor listed in the brackets under (R1.) only adds confusion to the Requirement. In (R1.), only list those specific items that are required according to the new standard and remove the reference to the Violation Risk Factor. The VRF and VSL information should be in a separate dedicated section and not in the requirement section.
No

Question states R2, R3, and R4. Assume the question is referring to (R1.2), (R1.3), and (R1.4)? (R1.3) and (R1.4) does not give appropriate time to gather data, run studies and perform field investigations for complex events where a Misoperation can occur. Recommend changing the 120 day requirement to 180 days. Remove Box with “Rational for R1”. It is not needed in the standard. In (R1.2), (R1.3), (R1.4) and (R1.5) the requirement wording starts with “A requirement…”, recommend removing “A requirement that” in each section. Suggest wording change as follows: R1.2 The responsible entity shall within 90 calendar days of each identified Misoperation, investigate each Misoperation to determine its cause and do one of the following: R1.3 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was identified develop one of the following: R1.4 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was not identified develop one of the following:
No
Adjust the VSL time horizons and Application Guidelines to reflect a change in (R1.3) and (R1.4) from 120 days to 180 days.
No
Recommend removing Measures from (B.) and creating a separate section for Measures. (B.) should be changed to (B. Requirements) Also change to (C. Measures) (D. Compliance) (E. Regional Variances) (F. Interpretations) (G. Associated Documents) Suggest wording change as follows: C. Measures M1. The responsible entity shall have a current copy of its procedure for identifying and addressing Misoperations in accordance with Requirement R1. M2. The responsible entity shall have documentation of Faults, BES Element operations, and identified Misoperations with their associated date of occurrence to demonstrate implementation of the processes related to Requirement R1, Part 1.1. M3. The responsible entity shall have documentation for each Misoperation investigation with their associated dates and either cause or where the cause of the Misoperation cannot be identified, any additional steps planned for identifying causes to demonstrate implementation of the processes related to Requirement R1, Part 1.2. M4. The responsible entity shall have documentation with associated dates of a CAP or an explanation of why there is no need to develop a CAP, for each Misoperation with an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.3. M5. The responsible entity shall have documentation with associated dates that includes a work timetable for implementation or an explanation of why no further investigation or actions will be taken for each Misoperation without an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.4. M6. The responsible entity shall have documentation with associated dates such as work management program records, work orders or other dated evidence, to demonstrate implementation of action plans related to Requirements R1, Part 1.5. M7. The responsible entity shall have documentation with associated dates that describes the manner in which the each CAP or action plan was completed to demonstrate compliance with the processes related to Requirements R1, Parts 1.5
Yes
The following comments are related to the “Quarterly Misoperations Reporting Data” table and template: 1) The fields associated with TADS reporting appear to be outside the scope of this reliability standard as stated in the Purpose, therefore we do not agree with inclusion of TADS. 2) The form does not address “action plans” that would be developed in response to Requirement R1, Part 1.4. The form appears to be collecting additional information that goes beyond the Purpose of the standard, i.e., “Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.” Specific information includes: Equipment Type; Facility Voltage (kV); Equipment Removed from Service; Relay Technology. The following comments are related to the reference document, SPCS Input on Uniform Misoperations Reporting: 1) The document and template appear to be focused on collecting data for the purpose of reliability metric ALR4-1. This additional data collection is outside the scope of draft standard PRC-004-3 and the proposed requirements stated in the associated Standards Authorization Request (SAR). Therefore, Dominion recommends that only data necessary to address the standard requirements be collected. 2) Section 3 Misoperation Categories 1st Paragragh and Table 1 Misoperations Categories are not consistent with the categories contained in PRC-004-3. Suggest revising document to include the five categories contained in the draft standard. 3) Section 4 Cause Codes 1st paragrah suggests there are six cause codes in Table 2 which is inconsistent with Table 2 that shows seven cause codes. Suggest revising document in the 1st paragraph to say seven cause codes. 4) Template is hard to use because of the number of horizontal columns of data being requested. The number of fields of data being requested seems to

be excessive. Any way to reduce the number of fields? 5) Facility Name (Location of Misoperation) field – IS this asking for location that caused the misoperation or the location of the breakers that operated? For example, when a failed carrier set at Station A causes the other terminal at station B to misoperate during a fault, do I enter Station A or Station B? 6) Equipment Type field - includes Dynamic VAR Systems but does not include Static VAR Systems (SVC for example). Should SVC be included? 7) Facility Voltage (kV) field - includes a choice of <100. Since the BES is defined as those elements >100 KV, this choice should be deleted. 8) For a unit connected generating unit with a 230 kV – 13.8 KV GSU and the 230KV generator output breakers trip when the unit trips, what KV do I enter? For a generator that has a 13.8 KV output breaker and a 230 kV – 13.8 kV GSU and the 13.8 KV breaker trips when the unit trips, what KV do I enter? 9) Equipment Removed from Service field – Isn't this the same information as the Equipment Name field? In the example provided there is no difference in what was entered. The Field Value info apparently limits this to Circuits, Transformers, Buses (and also breakers if the breaker is the only element to trip). Does "Circuits" mean the same as Lines? Suggest Circuits be changed to Lines. Do we include generators? Note that TADS does not require reporting of breaker trips unless a Line or Transformer is affected, shouldn't Misoperations do the same? Note that TADS does not include reporting of Buses or many of the other Equipment Types mentioned in the Misoperations template. Do you want all Equipment Types listed or only Lines and Transformers? We suggest it be limited to one entry focusing on the Equipment (ie Element) that misoperated. 10) Event Description field – The title using the word Event seems to entail the overall event which could include correct operations and misoperations, and the description indicates a brief description of the event and a detailed misoperation description. But the example data seems to indicate only a misoperation description. Can you include as an example description that has a problem on one line and another line overtrips. 11) Causes(s) of Misoperation field – Field is named Cause but description asks for root cause(s). Are you looking for one or are you asking for more than one to be entered? Suggest that the word "root" be removed from description. TADS and other industry benchmarking use Cause not root cause. Suggest that only one choice be allowed for entry. 12) Protection Systems/Components that Misoperate field – Is this redundant since you have asked for a detailed description of the Misoperation in the Event Description field? 13) Relay Technology field – suggest that only one choice be allowed. What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank. 14) Actual CAP Completion Date field – Change name to CAP Actual Completion Date be consistent with the CAP Target Completion Date field. 15) If the SDT ultimately decides to use one or more of the availability reporting systems (TADS or GADS or DADS), we have the following questions/comments: a. Cause Code field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank b. Event ID(s) field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank
Yes
Conflict: Collection of additional data pursuant to Section 1600 of NERC's Rules of Procedure, such as TADS information, does not belong in a NERC Reliability Standard.
Regional Variance:
Regional Variance: WECC Should consider the fact that WECC has Misoperation requirements that are not recognized by the other regions and the purpose of this standard is to standardize Misoperation documentation, reporting and definition of a Misoperation. Suggest no regional variances be allowed.
Yes
Dominion offers the following comments: 1) The "Rationale for R1" suggest that this revision will afford "enhanced reporting and the development of performance metrics that indicate overall system health, as well as facilitate the sharing of 'lessons learned'." Dominion notes that both performance metrics and lessons learned are outside of the scope of this reliability standard. Additionally, NERC is developing an Event Analysis process (currently in field trial) that includes a lessons learned component. Suggest NERC review the current process of blending data collection for other purposes with compliance. 2) The "Guidelines and Technical Basis" section appears to contain language that one could interpret as expanding the Requirements. Suggest clearly noting that this section is guidance only and not intended for compliance. 3) Section (5. Background) should be removed from the standard. This has no relevance to the Requirements or Measures of the new standard. 4) PRC 003 had the Regional Entity as a Functional Entity under Applicability; previous versions of PRC 004 have the TO, GO and DP listed as the Functional Entities under Applicability. PRC004-3 Background states that "PRC 003-1 is not enforceable…" and "This represents a potential reliability gap". According to PRC 004-3, responsible entities are to report to the Regional entities quarterly, so why

isn't the Regional Entity listed in the new standard as a Functional Entity? Is the objective to require the regions to submit the data collected to NERC? 5) (R1.5) does not allow for extending the CAP beyond the pre-determined timeline when system conditions will not allow for equipment removal, outages, or project schedule changes. There are circumstances where outages continue to move and schedules are adjusted due to operating conditions or limitations that are beyond the control of those developing a projected CAP work timetable. Timetables can be set but it is not unusual that later, when the work is to be performed, that system conditions dictate a change in the schedule. 6) In (C.1.4) the Regional Entity and ERO references require more emphasis by creating a separate section listing Regional Entity requirements. 7) In the Application Guidelines; the Misoperation Definitions (1 - 5), could include better examples or “bulleted” examples. 8) Consider not switching to landscape in the middle of the document. If landscape must be used move Regional Variances, Interpretations, and Associated Documentation to a new page. 9) Need to revise “Guidelines and Technical Basis” section to include Slow trip – other than Fault
See response to Question 6 above.
Individual
Michael Moltane
ITC
Yes
No
Within 1.1.1 the wording “and BES Protection System operations” may be interpreted to include all components within a Protection System which could lead to a monumental task and is not necessary if no outage occurred. 1.1.2 should be written to read simpler. Suggested changes: 1.1.1 Document and review all BES Faults or outages caused by BES Protection System operations. 1.1.2 Identify and document all Misoperations.
No
Because of coordination to shutdown the associated equipment, the time to investigate may exceed the time limit of 90 calendar days following the misoperation.
No
Answered No because of issues with meeting present time limit.
No
Within M2 “Protection System operations” should not be included. Suggest changing this to “BES outages”.
Yes
Misoperation reports can be quite lengthy to provide the needed details. Because there can be significant information for an adequate report a spreadsheet is not the best way to collect and distribute this data. Higher level software applications should be used.
Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the first or second half of the year. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
Suggest changing the first bullet to begin “Review all Faults or outages caused by Protection System operations…”. The draft standard 4.2.2 indicates that SPS, RAS and UVLS programs are excluded and this should also be indicated in the SAR.
Group
Pacific Northwest Small Public Power Utility Comment Group
Steve AlexandersonPE
No
The emphasis on the Protection System disregards the effect the breaker might have, since the breaker is not part of the NERC definition of Protection System. The consequences of a slow or failed

circuit breaker operation are similar to those of slow or failed protection system operation and should be treated the same. The comment group is concerned regarding the definition of Slow Trip as a “Protection System operation that is slower than planned.” How much slower than planned? How do we prove what may have been “planned” many years ago? And even if the settings, documentation, and trip times agree within some not yet defined tolerance; the “plan” itself may be too slow to provide an adequate coordination margin or to prevent instability when relay error, CT error, or subsequent system changes are considered. We propose eliminating the “plan” and looking at the result. We see that Slow Trip is more narrowly defined in the Guidelines and Technical Basis document, but believe this should be extended to the official NERC definition as well. 1. Failure to Trip - During Fault - Any failure of a Protection System or associated protective device to operate for a Fault within the zone it is designed to protect. 2. Failure to Trip - Other Than Fault - Any failure of a Protection System or associated protective device to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the it was intended to operate. 3. Slow Trip - Any Protection System or associated protective device operation that is slower than needed to prevent miscoordination or system instability for a Fault within the zone it is designed to protect.
No
Please see our answer to Q1. Slow tripping events that went according to “plan” are not identified as misoperations even though the result may not have been intended. Slow or failed breaker operation are also not identified as misoperations.
No
While we realize many entities may want or need the structure presented, we can see situations where the cause would be immediately evident and can and should be rectified at the time of the initial site visit. The problem and corrective action would then be documented afterward. While the second bullet of 1.3 suggests this might be allowed, it is not explicitly so stated. In the name of reliability, shortcuts such as this should be explicitly allowed in order to avoid repeated identical misoperations caused mainly by the standard process itself.
No
M6 and M7 appear to be duplicative. Please combine into a single measure, or more clearly state how they are different.
Yes
The misoperation category dropdown list does not match the five categories of the definition.
Yes
Conflict: Section 215 of the Federal Power Act At least one regional entity is consistently applying PRC-004-1 to distribution systems in violation of the FPA. Version 3 adds nothing to limit or clarify the extent of the standard’s reach.
Group
LG&E and KU Energy
Brent Ingebrigtson
No
LG&E and KU Energy believe that further clarity is needed in the definition of misoperation. Specifically: Item #3 Slow Trip the Standard should specifically exclude those incidents involving slow “total clearing times” that are due to mechanical (or other) problems with the breaker, where all protection system components operated as expected. Item 4 Unnecessary Trip During Fault. The definition should include unnecessary trips due to improper coordination of relay operating times. (Example: Zone 2 or Zone 3 trip occurring for a fault within its desired reach (zone), but prior to the desired time delay)
No
Much more than Misoperations is required in R1.1.1. 1) The GO/DP would not have knowledge of BES faults outside the boundaries of GO or DP, and this requirement should only involve the TO; 2)

Reporting correctly operating equipment will not increase the reliability of the BES system. Any operator-initiated action or normal/expected operation of relays should not require documentation when the goal of this standard appears to be about “Misoperations”. Having to document/investigate correct operation will delay performing required actions to bring a unit on-line to support the BES system.
No
We assume the SDT is referring to R1.2, R1.3, and R1.4 as there are no other requirements shown as R2, R3, and R4. Therefore, we have the following comment on R1.3: On Requirement R1.3, could the SDT clarify a little bit better that only a timetable and plans are needed to be completed within the 120 days, and not that the entire correction be completed within 120 days. Currently, R1.3 could be interpreted either way. Therefore, so that an auditor would not interpret it that the corrective action plan needs to be completed within 120 days, this needs to be clarified. Because GO’s oftentimes have to wait to complete a corrective action plan until the next outage on a unit, which would probably be greater than 120 days.
Yes
This seems to be the Excel Spreadsheet that NERC has already placed in force effective with 2Q 2011 reporting of Misoperations
Individual
Dale Fredrickson
Wisconsin Electric
No
The 5th category, "Unnecessary Trip – Other Than Fault", should also include an exception for trips which occur during onsite testing or maintenance work on the associated protection system. This exception is in the existing definition, and we maintain it should remain in the new definition. This is needed to allow exceptions for trips which may occur during commissioning or when making modifications due to the complexity of modern protection and control schemes.
Yes
Yes
The second bullet under R1.2 is unnecessary given R1.4. Also, replace “timetable” with “schedule” in 1.3, 1.4, and 1.5. The “…was (were) …” references in R1.3 and R1.4 should be replaced with the plural case alone for clarity. E.g, “…for all Misoperations for which the causes were identified.”
No
In M1 through M5, the adjective “written” list, report, etc should be removed since any such evidence may be electronic and not necessarily written on paper. In M5, replace “work timetable” with “schedule”. M6 should be replaced by a simpler statement like, “The responsible entity shall have dated evidence, such as work management records or other evidence, to demonstrate completion of all plans required by R1.5.” M7 is superfluous to M6 and should be removed.
Group
APM Members

Jason Marshall
No
It is not clear which definition of Protection System is intended to apply to the definition. Does the current FERC approved definition apply or does the definition approved by the NERC BOT on 11/19/2010 apply. The meaning of Misoperations will be different based on the two definitions. The implementation plan does not make it clear when the new definition will take effect and when the old one will be retired.
No
While R1 is sufficient to identify Misoperations, there are several issues with the requirements. In R1, use of Protection System as a description with Misoperations is redundant. The proposed definition of Misoperations includes Protection System. While we understand Part 4.2.1 of the Applicability section limits the applicability of the standard to Facilities that are part of the BES, we are concerned that the applicability section could be overlooked. Thus, we suggest the language (“Distribution Provider that owns a BES Protection System”) from the previous version of the standard be incorporated into the requirements. The language of the “within its system” should be replaced with “on its equipment”. The Generation Owner, Transmission Owner and Distribution Providers don’t have systems in the traditional sense. They own parts of the System. “On its equipment” should be appended to the end of Part 1.1.1. Otherwise, the part could be inadvertently interpreted as applying to every BES Fault and BES Protection System regardless of equipment ownership. For example, TO A might have to evaluate a Fault on TO B’s equipment. Clearly, this is not the intent. The second bullet under Part 1.2 and the bullet under Part 1.4 are redundant. Both require the registered entity to identify additional steps for an investigation.
No
We disagree that the VRF is consistent with other Reliability Standards. The SDT cites the need to deviate from the Medium VRF assigned to the similar requirement of EOP-004-1 R2 because it does not include implementation of corrective actions after the analysis. We disagree with this assessment as there is an implied obligation to implement any recommendations from analysis done to comply with EOP-004-1 R2. NERC investigative and enforcement personnel have routinely expected implementation of corrective actions from investigations. Thus, for consistency (as required by FERC Guideline 3), the VRF for PRC-004-3 R1 should be Medium. We disagree with inclusion of Operations Planning in the Time Horizon. This is a backwards looking analysis. While it does correct for forward looking operations, it is not intended for planning but to simply correct an operational issue. Otherwise, Operations Assessment should be eliminated as a category as the purpose of looking backwards is to correct operations going forward and another category would always be selected along with Operations Assessment. Any late completion of the CAP results in a High VSL. The drafting team should consider graduated steps based on the lateness of completion. Missing the CAP completion work timetable by a few days is not nearly as big a violation as missing the CAP work timetable by months. The second to last High VSL expands upon the requirement by mentioning delivery dates which would violate FERC Guideline 3 for VSLs. The requirements establish that a work timetable must be established. A timetable could be based on quarters rather than specific dates. If specific dates are desired, the requirement should be fine tuned to make this clear. Several of the VSLs mention a “declaration”. These VSLs should be expanded to match the language of the requirement more closely for clarity.
No
M1 is not consistent with the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC states that an entity may be held in violation of the requirement if it cannot produce previous versions of a procedure. Six years seems quite excessive for data retention. Three years should be sufficient. Six years appears to have been selected to match the audit cycle of the applicable functional entities. NERC contemplates that the data retention period may not be as long as the audit period in the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. Thus, it is not necessary for the date retention period to match the audit cycle.

Group
PPL Generation
Annette Bannon
No
The draft document defines several categories of Misoperation, of which the last is, "Unnecessary Trip - Other Than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate." The NERC glossary presently states, "Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity." It appears that NERC is dropping the exception for maintenance and test-related relay trips. It would be best to retain the present definition, since such trips usually have little on no bearing on long-term operational reliability.
No
Requirement 1.2 states, "A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s)." This should be clarified to be “within 90 calendar days of identifying a Misoperation.” Requirement 1.3 indicates within 120 days, the Registered Entity shall develop a CAP that includes “Final corrective or mitigating actions to reduce potential impacts to BES reliability.” This should be clarified to be “Final corrective or mitigating actions the Registered Entities plans to complete that reduce potential impacts to BES reliability.” It should be clear that not all “Final corrective or mitigating actions” need to be complete by the 120-day timeframe. Also, as suggested above, the language “within 120 calendar days” should be clarified to be “within 120 calendar days of identifying a Misoperation.”
Requirement 1.5 states that the procedure shall include, "A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented." Schedule changes may be needed as a result of unforeseen events. This should be clarified to be “A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable or document the basis for needed schedule changes. The procedure shall also include a requirement to document its completion as implemented.”
Group
Florida Municipal Power Agency
Frank Gaffney
No
We support the use of a Rapid Development Team (RDT) to help speed up the process; however, we only support the RDT drafting the SAR and not the first draft standard. We do not believe an RDT without broad industry representation drafting a standard meets the intent of the Federal Power Act, Section 215 (c)(2)(A) for a "fair stakeholder representation". It is also out of alignment with the Rules of Procedure, Standard Process Manual. And, it is presumptuous to assume that the SAR will not have significant comments that will change the scope and direction of the standard, or that the Standard Development Team, once fully formed, will not scrap the work done by the RDT and start all over again wasting time and effort. As a result, we choose not to comment on the standard, implementation plan, etc., and we only offer comments on the SAR and white paper and highly encourage NERC to reconsider how it deploys RPDs.
No
see comments to Question 1

No
see comments to Question 1
No
see comments to Question 1
No
see comments to Question 1
No
see comments to Question 1
No
see comments to Question 1
see comments to Question 1
see comments to Question 1
A concerning statement in the SAR is the proposal to add a requirement to the standard to: "Review all Faults or Protection System operations on the BES to identify those that are BES Protection System Misoperations". We are uncomfortable with the word "review". We would imagine only those protection system operation that fell outside of a certain tolerance would need to be reviewed, e.g., more than one Element tripped, the trip took longer than X cycles, a trip happened without a fault, etc. Review implies something more than looking to see if a criteria was met for further review. So, does review mean to evaluate whether certain criteria was met, or to do a thorough review? We're concerned with the administrative burden of having to do more than a high level review for each and every protection system operation or fault. What sort of evidence would be required to prove that we looked at every Protection System operation and fault on the BES? This could create an unnecessary administrative burden on the industry. Also, in the white paper, the paper identifies incorrect settings as a misoperation (see Table 2 on Cause Codes). To us, incorrect setting is not a misoperation and to call it such creates double jeopardy. If an engineer calculates the incorrect setting for a relay, that should be a PRC-001 standard implication. If a relay tech puts the wrong setting in the relay and tests to that wrong setting, that should be a PRC-005 issue, and not a PRC-004 issue.
Group
Bonneville Power Adminstration
Chris Higgins
No
BPA believes that the new definition does not specify if an inadvertent relay operation due to maintenance or other human activity is a misoperation. This occurs fairly often, and to prevent a lot of confusion, the definition must specify whether or not this is a misoperation. In the previous definition, this was not a misoperation, and we would prefer that it also not be a misoperation in the new definition. Another comment is that the previous definition of a misoperation is included in the Background section of the draft standard. BPA feels that this is confusing to list this old definition within the standard because it appears that the standard is providing this definition as part of the standard. BPA suggests moving the entire Background section out of the standard.
No
BPA feels that R1.1 is ambiguous. In R1.1.1, what does it mean to document and review a BES fault? In R1.1.2, identify and document all misoperations associated to what? In R1.1.3, BPA believes the word "address" is ambiguous.
Yes
BPA believes the alloted time seems adequate.
No
BPA believes that under M1: Entities should not be required to provide documentation of the processes and procedures that they use to identify and address misoperations. M2 thru M7: BPA feels that the measures given are overly burdensome. Reading these measures would lead one to believe that NERC has an expert panel of protection engineers on standby, waiting to sift through the data provided for each misoperation, and give expert guidance to the industry. BPA feels that this is not accurate, as this NERC standard will only capture an overview of the number and types of

misoperations experienced in the industry. BPA feels that the documentation requested will require many hours of work, and feels that the only review of it will be from an auditor whose only purpose is to make sure that it was accumulated. BPA feels that the burden of providing these detailed investigative reports and corrective action plans will result in less productive time for the individuals who are the ones capable of solving the problems. BPA feels that only basic information, such as an elementary description of the misoperation, and a basic corrective action plan should be required. Lists of faults, investigative reports, work management program records, etc. seem to be unnecessary. If the experts at NERC need more information on a particular misoperation, they can always request it.
Yes
If NERC really needs the information in the this table, then BPA will support it. However, the way that TADS event IDs are assigned, doesn't easily align with relay misoperations and may be cumbersome and BPA questions whether or not it is be necessary to provide the TADS event ID. BPA suggests that the quarterly reporting requirement given under Section 1.4, Additional Compliance Information is misplaced and suggests that it be given as "ONE" of the requirements. BPA feels that the quarterly reporting table should be all the information that is required, and suggests that measures M1 thru M7 should be removed.
No
BPA feels that in regards to the final paragraph of Section 5, Background, states that with regard to the WECC regional misoperation standard (PRC-004-WECC-1), complying with the more stringent standard will ensure compliance with the less stringent as well. BPA feels that this is not correct because the two standards have different requirements, and will require different actions to be in compliance with both. BPA believes that it would be helpful if WECC would rescind PRC-004-WECC-1. BPA asks, "Will the regional criterion, such as PRC-003-WECC-CRT-1 be rescinded?"
BPA believes that the requirements in this standard to create and provide procedures and detailed descriptions of the processes used to analyze relay misoperations are burdensome. In addition, BPA feels that the requirement to provide your own processes and procedures results in extra steps that waste valuable time. Documenting these processes and procedures and then providing them in self-certifications and at audits results in appreciable work. This step also results in one more potential audit violation. This approach is the one that was used in PRC-005-1. There it resulted in inconsistent levels of relay maintenance between entities and inequitable penalties. That approach is being dropped in PRC-005-2, and BPA believes that it should not be used in this standard either. A more concise and acceptable standard would simply specify the minimum requirements for analyzing and documenting relay operations and not require the documentation of procedures and detailed descriptions of the processes used by individual entities.
Individual
Greg Rowland
Duke Energy
No
• On #2 “Failure to Trip – Other Than Fault”, need to add the word “abnormal” before the word “non-Fault” in order to exclude normal non-Fault situations such as where protective relays are used for control functions (i.e. reverse power relays on generators). • On #4 “Unnecessary Trip – During Fault”, need to replace the phrase “not within the zone it is designed to protect” with the phrase “for which the Protection System is not intended to operate”. The current wording would not require reporting of unnecessary trips for a fault within the zone the Protection System is designed to protect. For example, we use over-reaching protection for breaker failure protection. • On #5 “Unnecessary Trip – Other Than Fault”, It should be made clear where failed relays would be reported. For clarity, add the phrase “or any other normal system condition” after the phrase “loss of excitation”.
No
In the lead-in paragraph for R1, the word “all” should be replaced with “BES” for clarity. NOTE: R1.2, R1.3 and R1.4 are addressed in our response to question #3 below.
No
• R1.2 – replace the phrase “identified Misoperation” with the phrase “Protection System Operation”

to clarify that the clock starts with the Protection System Operation, not when you identify a Misoperation. Also replace the phrase “investigate the Misoperation” with the phrase “analyze any Misoperation”. • R1.2 first bullet – Reword as follows: “For each Misoperation where the cause(s) are identified, document the analysis and the cause(s) determined.” • R1.2 – Increase the time to 120 calendar days and note under the second bullet that where a transmission or generation outage is required to complete an analysis (i.e. nuclear switchyard), it’s permissible to document that as additional steps planned to identify the cause(s). • R1.2 second bullet - Change the word “investigation” to “analysis”. • R1.3 – Change 120 to 60 calendar days, and replace the phrase “of the Misoperation’ with the phrase “of completing the analysis in R1.2”. • R1.4 – Delete R1.4 because it is redundant to parts of R1.2 and R1.3 • R1.5 – Modify R1.5 so that a Registered Entity can revise its CAP or action plan as outlined in its timetable, in order to deal with changes in outage schedules, etc.
No
VSLs should be revised consistent with our comments on the requirements.
No
• M5 – delete this Measure associated with R1.4 consistent with our response to question #3 above. • M6 and M7 should be combined.
Yes
• TADS transmission data may not be accessible to generators, and generator data may not be reported in TADS. • Need to add a 100 kV option on the template (column J).
No
Yes
• We like having the “Guidelines and Technical Basis” as part of the standard. • For clarity, revise the third paragraph under Section 5 of the “Guidelines and Technical Basis” as follows: Failure to automatically reclose after a fault is not included as a Protection System Misoperation because reclosing equipment is not included under the definition of Protection Systems. Further, operations which are initiated by control systems (not by Protection Systems), such as those associated with generator and excitation controls, protection used during generator startup and shutdown (such as reverse power relaying), or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are also not Misoperations of a Protection System. • The requirements to have documented processes for identifying, analyzing and reporting Misoperations as well as CAP and action plan tracking may impact some entities. For such entities, the Implementation Plan may not allow sufficient time to both develop and implement additional processes.
Individual
Amir Hammad
Constellation Power Generation/Constellation Energy Nuclear Group
No
The definition language is not clear on failures due to human intervention. For example when TO testing in a switchyard causes a GO trip, is that a misoperation?
No
The documentation requirement under 1.1.1 is too broad and onerous. As an example, some generating units upon shut down may have lockout relays associated with opening the generator breaker. This technically is a protection system operation, but is working as designed. If that same generating unit were to cycle every day, then a report identifying the operation and classifying it as not a misoperation would need to be created every day. Therefore, requiring the documentation of all protection system operations is purely an administrative requirement. The burden of documentation does not encourage reliability and should be carefully considered as part of the standard.
No
The “no” response is due to confusion in the question. We suspect that the requirements intended for reference were R1.2, R1.3 and R1.4. The time allotments seem reasonable.

Yes
Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary. "XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Individual
Tracy Richardson
Springfield Utility Board
No
SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect penalty funds.
Yes
1)Under "Applicability" in PRC-004-3, SUB recommends that the language lists Functional Entities (TO, GO, DP) who own the following Facilities (Protection Systems, SPS). The current version of the PRC-004-3 draft lists Functional Entities and Facilities as separate applicability. 2)SUB would ask for PRC-004-3 to clarify whether or not Functional Entities would be required to submit a quarterly report if they do not have any misoperations occur during the quarter. SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect penalty funds.
Individual
Patricia Robertson
BC Hydro
Yes
Yes

BC Hydro requests clarification for the unintentional protection system operation due to maintenance or testing. Is this unintentional operation considered a misoperation?
Yes
Yes
BC Hydro requests clarification for underfrequency load shedding schemes (UVLS). Would they fall under this standard?

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Protection System Misoperations – Project 2010-05.1

The Protection System Misoperation Identification and Correction Drafting Team thanks all commenters who submitted comments on the first draft of the standard for Protection System Misoperation Identification and Correction. The standard and associated documents were posted for a 30-day public comment period from June 10, 2011 through July 11, 2011. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 52 sets of comments, including comments from approximately 146 different people from approximately 106 companies, representing 10 of the 10 Industry Segments, as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560, or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

The definition of Protection System Misoperation has been modified to reflect comments received. Statements were incorporated into the definition so that only the overall performance of the Protection System is considered when determining a Misoperation. The non-functioning of high-speed Protection Systems required by the performance requirements of the TPL standards has been explicitly incorporated. An additional category of "Slow Trip – Other Than Fault" has been added for consistency. Exclusion of Protection System operations because of on-site maintenance, testing, construction, or commissioning activities has been added due to stakeholder comments. An exclusion to the category "Unnecessary Trip – During Fault" was added related to the proper remote Protection System operation. Comments related to "Fast Trip" were not incorporated because this type of Misoperation is included in the category "Unnecessary Trip – During Fault." Comments related to exclusion of incorrect settings or other design flaws were not incorporated because these fit within one of the established causes of Protection System Misoperation developed by the IEEE Power System Relaying Committee, Working Group I3.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

Some commented on the applicability of the requirements to the Distribution Provider and Generator Owner and the applicability to non-BES Protection Systems, even though the Applicability section specified that the requirements only applied to Protection System(s) of Facilities that are a part of the BES. The standard is applicable to Distribution Providers and Generator Owners and Transmission Owners because these entities can own Protection Systems of Facilities that are a part of the BES.

Some commenters asked why UFLS Misoperations are included in this standard. The drafting team responded that UFLS Misoperations were included because they are not explicitly covered by any existing NERC standards. Sudden Pressure Relay Misoperations are not included because they are not currently part of the Protection System definition.

Many commented that Requirement R1 was too all-encompassing since it was the only requirement in the standard. For example, two very different items, documentation of a process and implementation of the process were in the same requirement. As such, many commenters were concerned that only one VRF existed for the entire standard and the “High” VRF was not indicative of most of the parts contained within Requirement R1. The new draft has separate requirements for the process documentation, the implementation of the process, and other steps in the Misoperation investigation, correction, and reporting. VRFs were established for each of the new requirements.

Numerous commenters were concerned about the 90-day time limit to complete the investigation; including, possibly, taking necessary outages. The SDT revised the standard by increasing the timelines and clarifying the steps involved to complete the investigation of a Misoperation. Allowances for long investigations under an action plan were added. Many commenters were confused about the starting point of the time intervals associated with the Misoperation investigation. The SDT revised the standard to clarify the starting point of the Misoperation investigation (new Requirement R2) is the occurrence of the Protection System operation. Other commenters were concerned about compliance with the timelines in the standard after a natural disaster or significant system event. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: “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.”

Some commented that reporting Misoperations should be included as a requirement instead of in the Compliance Section. The drafting team consulted with NERC staff and decided that the Compliance Section is the appropriate location for Misoperations reporting. Several commenters proposed to make the Misoperation reporting template the official evidence of compliance. Attachment 1 “Quarterly Misoperations Reporting Data” reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed so as to identify those that are Misoperations. Several commenters had concerns with the reporting form requiring TADS event I.D.’s. The correlation between Protection System Misoperation and TADS events is needed to determine Metric ALR4-1, developed by NERC Operating and Planning Committees under NERC’s Rules of Procedure, Section 809. Several commenters pointed out inconsistencies between the new definition of Misoperation and the categories in Attachment 1. The language in Attachment 1was revised to match the language approved for use in the revised Standard PRC-004. Other inconsistencies will also be resolved. Once the method (website, database, spreadsheets, other forms, etc.) of reporting is established, questions on how to remove previously reported Misoperations that have been determined to not be Misoperations and how to report no additional Misoperations during a reporting quarter will be clarified. One commenter had a concern with quarterly reporting requirements versus, possibly, semi-annual reporting. While some regions require semi-annual reporting today, on October 22, 2010, NERC's ERO Executive Management group endorsed an ERO-RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.

Several commenters expressed concern that the use of the word "written" does not allow for electronic data retention. The word "written" has been removed. The measures now provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.

Several commenters expressed concern that the data retention period should not exceed the audit cycle. The Evidence Retention section was redrafted to follow the NERC Rules of Procedure, Appendix 4C, CMEP Section 3.1.4.2, which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.

A few commenters questioned whether Protection System operations occurring during generator synchronization would be covered under PRC-004-3. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these operations are excluded because the generating unit is not synchronized and is isolated from the BES.

Several comments were received on possible conflicts with other NERC standards, Section 215 of the Federal Power Act, and NRC regulations. A review of the issues cited was performed and no conflict is believed to exist.

In response to one comment, the drafting team modified the Background statement to better reflect the interaction between this standard and the WECC regional Misoperations reporting standard. Regional standards for Misoperations reporting can still go beyond what the new NERC PRC-004 will require.

Numerous commenters were concerned about the prescriptive nature of the Guidelines and Technical Basis section of the standard. The SDT clarified that the Guidelines and Technical Basis section of the standard is not mandatory and enforceable and is included to provide insight into the thought processes of the drafting team as they developed the requirements.

One commenter wanted to be exempt from this standard because they are a nuclear generator operator and fall under NRC rules. The NRC rules cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security, and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.

A few commenters expressed concern that the time allowed to develop and implement the required additional processes was too short. The SDT agreed and changed the effective date (implementation time) to 12 months.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Mike Garton	Dominion Resources Services, Inc.		5
9.	Brian L.Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

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

11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	John Seelke	Public Service Enterprise Group Company	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Mikhail Falkovich	PSEG	ERCOT	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul DiFilippo	Hydro One	NPCC	1, 3
2.	DAvid Kiguel	Hydro One	NPCC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Bill Middaugh	Tri-State Generation and Transmission Ass'n - System Protection	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Pearsall	Tri-State Generation and Transmission Ass'n.	WECC	1, 3, 5
2.	Gary Preslan	Tri-State Generation and Transmission Ass'n.	WECC	1, 3, 5

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

3. Matthew Leyba	Tri-State Generation and Transmission Ass'n.	WECC	1, 3, 5
4. LeRoy Martinez	Tri-State Generation and Transmission Ass'n.	MRO	1, 3, 5

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

Additional Member	Additional Organization	Region	Segment Selection
1. Brian Orians	FE	RFC	5
2. Jim Detweiler	FE	RFC	1
3. Leslie Aleva	FE	RFC	1
4. Robert Loy	FE	RFC	5
5. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Alvin Depew	Pepco Holdings Inc	RFC	1, 3
2. Mark Godfrey	Pepco Holdings Inc	RFC	1, 3
3. Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Bill Shultz	Southern Company Generation					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Tom Higgins	Southern Company Generation	SERC	5
2. Terry Crawley	Southern Company Generation	SERC	5
3. Therron Wingard	Southern Company Generation	SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Cynthia S. Bogorad	Transmission Access Policy Study Group	X		X	X	X	X				
No additional members indicated.												
9. Group	Jonathan Hayes	SPP Reliability Standards Development Team		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Clem Cassmeyer	Western Famers Electric Cooperative	SPP	1, 3, 5
2. Nick Henry	FERC	NA - Not Applicable	NA
3. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4. Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
5. Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
6. Shawn Jacobs	Oklahoma Gas & Electric	SPP	1, 3, 5
7. Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5
14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Connie Lowe	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1, 3, 5, 6
2.	Louis Slade		RFC	5, 6
3.	Michael Gildea		MRO	5
4.	Mike Garton		NPCC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
2.	Dave Proebstel	Clallam County PUD No.1	WECC	3

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

3. Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
4. Ronald Sporseen	Central Electric Cooperative	WECC	3
5. Ronald Sporseen	Consumers Power	WECC	1, 3
6. Ronald Sporseen	Clearwater Power Company	WECC	3
7. Ronald Sporseen	Douglas Electric Cooperative	WECC	3
8. Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
9. Ronald Sporseen	Northern Lights	WECC	3
10. Ronald Sporseen	Lane Electric Cooperative	WECC	3
11. Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
12. Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
13. Ronald Sporseen	Lost River Electric Cooperative	WECC	3
14. Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
15. Ronald Sporseen	Umatilla Electric Cooperative	WECC	3
16. Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
17. Ronald Sporseen	West Oregon Electric Cooperative	WECC	3
18. Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
19. Ronald Sporseen	Power Resources Cooperative	WECC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				

No additional members indicated.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Jason Marshall	APM Members						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Johnny York	Brazos Electric Cooperative	ERCOT	1, 3, 5
2. Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5
3. Lindsay Shepard	Sunflower Electric Cooperative	SPP	1, 3, 5
4. Mark Jones	SMECO	RFC	3, 4
5. Susan Sosbe	Wabash Valley Power Association	RFC	3, 4

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	Annette Bannon	PPL Generation					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Don Lock	PPL Brunner Island, LLC	RFC	5
2.	PPL Holtwood, LLC	RFC	5

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

3.		Lower Mount Bethel Energy, LLC	RFC	5
4.		PPL Martins Creek, LLC	RFC	5
5.		PPL Montour, LLC	RFC	5
6.	Dave Gladey	PPL Susquehanna, LLC	RFC	5
7.	Leland McMillan	PPL Montana, LLC	WECC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

				1	2	3	4	5	6	7	8	9	10
17.	Group	Chris Higgins	Bonneville Power Adminstration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Kerr	BPA, Electrical Engineer, Technical Operations	WECC	
2.	Dean Bender	BPA, Electrical Engineer, SPC Technical Svcs	WECC	

				1	2	3	4	5	6	7	8	9	10
18.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
19.	Individual	Bo Jones	Westar Energy	X		X		X	X				
20.	Individual	Greg Davis	Georgia Transmission Corporation	X									
21.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
22.	Individual	Silvia Parada Mitchell	NextEra Energy, Inc.	X		X		X					
23.	Individual	Antonio Grayson	Southern Company	X		X							
24.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
25.	Individual	Greg Froehling	Green Country Energy					X					
26.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie	X									
27.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
28.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Bob R. Davis	Private Citizen										
30.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
31.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
32.	Individual	Twila Hofer	PSE	X		X		X					
33.	Individual	Joanna Luong-Tran	TransAlta										
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Dan Hansen	GenOn Energy					X					
36.	Individual	Scott Berry	Indina Municipal Power Agency				X						
37.	Individual	John Bee on behalf of the Exelon Companies	Exelon	X		X		X					
38.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Brian Evans-Mongeon	Utility Services, Inc.								X		
42.	Individual	Thad Ness	American Electric Power	X		X		X	X				
43.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
44.	Individual	Armin Klusman	CenterPoint Energy	X									
45.	Individual	Steve Boutilier	BGE	X									
46.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
47.	Individual	Michael Moltane	ITC	X									
48.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
49.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
50.	Individual	Amir Hammad	Constellation Power Generation/Constellation Energy Nuclear Group					X					
51.	Individual	Tracy Richardson	Springfield Utility Board			X							
52.	Individual	Patricia Robertson	BC Hydro	X	X	X		X	X				

1. **The definition of 'Misoperation' has been revised. Do you agree with the proposed definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The definition has been modified to reflect comments received.

- Statements were incorporated into the definition so that the overall performance of the Protection System is considered in determining a Misoperation.
- Non-functioning of High-speed Protection Systems required by the performance requirements of the TPL standards has been explicitly incorporated.
- An additional category of "Slow Trip – Other Than Fault" has been added for consistency.
- Exclusion of Protection System operation(s) because of on-site maintenance, testing, construction or commissioning activities has been added.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The new definitions only addressed "Slow Trip". "Fast Trip" could cause misoperation as well. Suggest that the new definition should include "Fast Trip". 2. In the definition of Slow Trip, the word "planned" should be replaced with "designed". Not all faults have characteristics as planned, but fall within a Protection System's designed capability. 3. The "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. Suggest retaining phrase similar to one in current definition: "Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity." 4. It can be said that Protection System Operations for settings that have been miscalculated or applied incorrectly are not Misoperations because the hardware operated correctly. It has to be made clear that even though the hardware might operate correctly, for these situations it does not operate as desired. Terminology that

		has been used for these operations is “correct but undesired”. Suggested rewording for “Unnecessary Trip-Other Than Fault”: Any Protection System Operation for non-Fault conditions such as power swings, undervoltage, over excitation, or loss of excitation for which the Protection System is not intended to operate. This would also include any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity, or correct but undesired operations because of settings that have been miscalculated or incorrectly applied.
Response: Thank you for your comments. **1. A “Fast Trip” is not by itself a Misoperation except perhaps when considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System’s zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an “Unnecessary Trip - during Fault.” This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.** **2. The SDT modified the definition based on your comment. We replaced the word “planned” with “intended”. The use of the term “designed” is inappropriate in this case as it could be postulated that a poorly designed system should operate much slower than expected or perhaps not at all.** **3. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads “and is unrelated to on-site maintenance, testing, construction or commissioning activities.”** **4. The SDT disagrees. Protection System operations because of settings that have been miscalculated or incorrectly applied cannot be misconstrued as a “correct” operation when looking at the overall performance of the Protection System. These types of operations are simply incorrect and readily fall into an Unnecessary trip category. It is important to realize that it is the overall Protection System performance being judged and not any individual piece of equipment such as a relay.**		
Public Service Enterprise Group Company	Yes	The definition is acceptable provided the clarifications in the “Guidelines and Technical Basis” section of the draft is part of the standard.
Response: Thank you for your comment. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.**		

Hydro One	No	The fifth category "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, "… unrelated to on-site maintenance and testing activity".
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Tri-State Generation and Transmission Ass'n - System Protection	No	1. There needs to be a continuation of the specific exclusion for operations that occur as a result of on-site maintenance or testing activity. It seems that the exclusion is intended to remain since there is no "Cause of Misoperation" associated with maintenance or testing. 2. We are not certain how the "Guidelines and Technical Basis" will accompany the new definition in the "NERC Glossary of Terms," but the last sentence in (1) of the Guidelines is not supported by the definition. We disagree that the failure of one high speed Protection System to operate when another does operate should not be classified as a Protection System Misoperation. There may be times when that philosophy is appropriate, but not usually. If the non-operating system can be shown to have simply not had time to operate, then that can be explained in the event report, but typically both high-speed Protection Systems should operate unless one is designed to have a delay. But if it has a delay it shouldn't be classified as high-speed.
Response: Thank you for your comment. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. The exclusion of this type of failure is based on the NERC SPCS recommendation to consider the composite Protection System of a given Element rather than the individual protective schemes, such as the primary and secondary protection, for an Element.**		
FirstEnergy	No	The last bullet of the current definition includes the phrase "unrelated to on-site maintenance and testing activity". We suggest this be retained in the proposed definition to alleviate any misunderstandings among the responsible entities.

Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Pepco Holdings Inc Affiliates	No	1. The original definition excluded protective system operations related to on-site maintenance and testing activities. The new definition does not. A true measure of the performance of a protective system should not include protective system operations caused or initiated by human errors during on-site activities. These include such things as failure to pull appropriate test switches during testing, inadvertently keying a direct transfer trip channel, accidently shorting or bridging a terminal block during construction activities while landing secondary cables, etc. As such, we would propose amending Item 5 of the proposed Misoperation definition as follows: 5. Unnecessary Trip - Other Than Fault - Any Protective System Operation for non-fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protective system is not intended to operate. Unintended Protective System Operations that occur during on-site maintenance, testing, construction, and/or commissioning activities are not considered Protective System Misoperations. (this qualification is consistent with the definition included with the proposed Misoperation reporting spreadsheet and with the intent of the original definition) 2. Also, the qualifying comments in the "Application Guidelines" section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the Misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a Misoperation and what does no
Response: Thank you for your comments. 1. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** 2. **Some of the information in the Guidelines has been incorporated in the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.**		
Southern Company Generation	No	The proposed definition is excessively lengthy. Items 1, 2, and 3 should be combined into one statement: Any failure of a Protection System to operate for a fault or non-fault condition as it is designed to operate. Items 4 & 5 should be combined into one statement: Any Protection System operation for a fault or non-fault condition when it was not designed to operate. Alternatively, all five statements could be replaced with this one

		statement: A Misoperation is either the operation of a Protection System when it should not have operated or the failure of a Protection System to operate when it should have operated.
Response: Thank you for your comments. **The proposed Misoperation definition is based on the established categories of relay system Misoperation developed by the IEEE Power System Relaying Committee Working Group I3. This definition is also meant to line up with the Misoperation Categories in the reporting form developed by the ERO-RAPA group. A sixth category was added to help clarify what constituted a failure of a Protection System to operate during a non-fault condition since the term “abnormal condition” is ambiguous. By adding this category, the Failure to Trip categories now mirrors the previously established Unnecessary Trip categories. Although it is certainly possible to shorten the definition by concatenating the categories into one or two sentences, it does not actually help in clarifying or correlating the definition to the Misoperation categories.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. Would like to add either in this section or in the application guidelines a reference to trips prior to synchronization would not be reported. They would be investigated and corrected but not reported. 2. We are concerned that the definition would lose clarity if the application guidelines are moved out of the standard. If this happens we would like to see some of the meat of the guidelines added to the definition.
Response: Thank you for your comments. **1. The SDT agrees that false trips prior to synchronization should not be reported because the unit is isolated from the rest of the BES. The Guidelines and Technical Basis section has been updated to address your comment. The paragraph reads: “A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation. These types of operations are excluded from review because the generating unit is not synchronized and isolated from the BES. Protection System operations which occur with the protected Element already out of service, that do not trip any in-service Elements cannot be Misoperations.”** **2. Some of the information in the Guidelines and Technical Basis will be incorporated in the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.**		
MRO's NERC Standards	Yes	

Review Forum		
Electric Market Policy	No	1. Problems with 3. Slow Trip Use of term “slower” in the definition (Page 3 of 16) and “delayed” in the Application Guidelines (Page 12 of 16) is vague. “Slower” seems to indicate an unintentional time period before tripping while “Delayed” implies an intentional time period before tripping. Slow trip definition introduces the term “planned” which adds confusion. 2. Reference to TPL standards implies the need for more and new System Studies. Must these studies be performed and documented prior to installation? What is requirement for keeping these studies current? 3. NERC Glossary definition of Misoperation makes reference to a failure to operate within a specified time for an abnormal condition. There is no mention of “Slow” trip for a non-fault condition in the proposed definition. 4. Only those terms that are in the NERC Glossary should be capitalized. 5. Suggest wording changes as follows: 1. Failure to trip - during Fault - Any failure of a Protection System to operate for a Fault within the zone it is intended to protect. 2. Failure to trip - other than Fault - Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate. 3. Slow trip - during Fault - Any Protection System operation that is slower than designed for a Fault within the zone it is intended to protect.4. Slow trip - other than Fault - Any Protection System operation that is slower than designed for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which it is intended to operate.5. Unnecessary trip - during Fault - Any Protection System operation for a Fault not within the zone it is intended to protect.6. Unnecessary trip - other than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate including trips occurring when no disturbance is present. Excludes on-site maintenance and testing.

Response: Thank you for your comments.

1. **The reference to “delayed” clearing in the Application Guidelines refers to specific situations when high-speed clearing is not required to meet TPL standards. However, even if high-speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). The SDT has modified the definition of Misoperation based on comments. The word “planned” has been replaced with “intended”. Information in the Guidelines on “Delayed Fault Clearing” has been incorporated in the definition.**

2. Yes, system studies need to be performed prior to installation of most BES equipment such as a generator to check adequate system performance. The current TPL standards address these studies and their frequency. **3. The SDT added the following language to the definition of Misoperation to address your comment: Slow Trip - Other Than Fault - A Protection System operation that is slower than intended for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.** **4. Thank you for your remark on capitalization. These words are part of a category header and are capitalized for emphasis.** **5. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Pacific Northwest Small Public Power Utility Comment Group	No	1. The emphasis on the Protection System disregards the effect the breaker might have, since the breaker is not part of the NERC definition of Protection System. The consequences of a slow or failed circuit breaker operation are similar to those of slow or failed protection system operation and should be treated the same. 2. The comment group is concerned regarding the definition of Slow Trip as a "Protection System operation that is slower than planned." How much slower than planned? How do we prove what may have been "planned" many years ago? And even if the settings, documentation, and trip times agree within some not yet defined tolerance; the "plan" itself may be too slow to provide an adequate coordination margin or to prevent instability when relay error, CT error, or subsequent system changes are considered. We propose eliminating the "plan" and looking at the result. We see that Slow Trip is more narrowly defined in the Guidelines and Technical Basis document, but believe this should be extended to the official NERC definition as well. 3. Failure to Trip - During Fault - Any failure of a Protection System or associated protective device to operate for a Fault within the zone it is designed to protect. 2. Failure to Trip - Other Than Fault - Any failure of a Protection System or associated protective device to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the it was intended to operate. 3. Slow Trip - Any Protection System or associated protective device operation that is slower than needed to prevent miscoordination or system instability for a Fault within the zone it is designed to protect.
Response: Thank you for your comments. **1. The definition of Misoperation is only for Protection Systems and the entirety of breakers is not included in the**		

definition of Protection Systems. This is not meant to minimize the importance of interrupting devices but to narrow the targeted area of review, analysis and corrective actions. **2. The SDT added the following language to the definition of Misoperation to address your comment: Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault Clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)** **3. The addition of the words "or associated protective device" to parts of the definition seems unnecessary as the performance of the Protection System is being judged and not that of the current interrupting devices, i.e. breakers, they operate.**		
LG&E and KU Energy	No	LG&E and KU Energy believe that further clarity is needed in the definition of Misoperation. Specifically: 1. Item #3 Slow Trip the Standard should specifically exclude those incidents involving slow "total clearing times" that are due to mechanical (or other) problems with the breaker, where all protection system components operated as expected. 2. Item #4 Unnecessary Trip - During Fault. The definition should include unnecessary trips due to improper coordination of relay operating times. (Example: Zone 2 or Zone 3 trip occurring for a fault within its desired reach (zone), but prior to the desired time delay).
Response: Thank you for your comments. **1. It is not necessary to specifically exclude mechanically slow breakers as breakers are not included in the definition of Protection Systems.** **2. The Unnecessary Trip – During Fault category is meant to cover improper coordination and other conditions. Please see the Guidelines and Technical Basis section of the draft standard for examples.**		
APM Members	No	1. It is not clear which definition of Protection System is intended to apply to the definition. Does the current FERC approved definition apply or does the definition approved by the NERC BOT on 11/19/2010 apply. The meaning of Misoperations will be different based on the two definitions. 2. The implementation plan does not make it clear when the new definition will take effect

		and when the old one will be retired.
Response: Thank you for your comments. 1. **The current FERC approved definition of Protection Systems is the one applicable to the Misoperation definition. The newer, more detailed definition was approved by FERC in February 2012, and will be effective April 1, 2013.** 2. **The new definition of Misoperations will take effect when the Reliability Standard PRC-004-3 is FERC approved.**		
PPL Generation	No	The draft document defines several categories of Misoperation, of which the last is, "Unnecessary Trip - Other Than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate." The NERC glossary presently states, "Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity." It appears that NERC is dropping the exception for maintenance and test-related relay trips. It would be best to retain the present definition, since such trips usually have little or no bearing on long-term operational reliability.
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Florida Municipal Power Agency	No	We support the use of a Rapid Development Team (RDT) to help speed up the process; however, we only support the RDT drafting the SAR and not the first draft standard. We do not believe an RDT without broad industry representation drafting a standard meets the intent of the Federal Power Act, Section 215 (c)(2)(A) for a "fair stakeholder representation". It is also out of alignment with the Rules of Procedure, Standard Process Manual. And, it is presumptuous to assume that the SAR will not have significant comments that will change the scope and direction of the standard, or that the Standard Development Team, once fully formed, will not scrap the work done by the RDT and start all over again wasting time and effort. As a result, we choose not to comment on the standard, implementation plan, etc., and we only offer comments on the SAR and white paper and highly encourage NERC to reconsider how it deploys RPDs.
Response: Thank you for your comment.		
Bonneville Power Administration	No	1. BPA believes that the new definition does not specify if an inadvertent relay operation due to maintenance or other human activity is a Misoperation. This occurs fairly often,

		and to prevent a lot of confusion, the definition must specify whether or not this is a Misoperation. In the previous definition, this was not a Misoperation, and we would prefer that it also not be a Misoperation in the new definition. 2. Another comment is that the previous definition of a Misoperation is included in the Background section of the draft standard. BPA feels that this is confusing to list this old definition within the standard because it appears that the standard is providing this definition as part of the standard. BPA suggests moving the entire Background section out of the standard.
Response: Thank you for your comments. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. The SDT is following the current template for a Results-based Reliability Standard which includes a Background section. The SDT believes showing the old definition of Misoperations in the Background section is appropriate.**		
Western Area Power Administration	No	1. The previous "out" for outages which occur during on-site maintenance and testing is missing from the new definition. We would definitely like to see this added. 2. We do like the "Guidelines and Technical Basis" section at the back of the standard which provides some clarification. Hopefully this section gets retained and we agree with most of what is stated, in particular it gives us an "out" for comm-aided protection which is not required by Planning Studies. 3. Misop Category 4 - it is desirable in some cases to "overprotect" or intentionally miscoordinate based on exposure and risk. For example, we tend to allow our Zone 1 elements to cover 85% of our sub transmission lines even though it will miscoordinate with high side tapped transformer protection. This is done so that we will react quickly to the majority of faults which occur mainly on the line. The incidence of high side faults on the tapped transformers is low and we accept the risk of over tripping in those cases. Allowance should be made for entities to intentionally miscoordinate where risk and value make sense. 4. Misop Category 5 - this should actually be strengthened to mention a trip which occurs for non-Fault conditions where the relay or protection system fails. Is this not a Misoperation?
Response: Thank you for your comments. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that**		

reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities." 2. The Guidelines and Technical Basis section is a part of the new template for Results-based Reliability Standards. 3. In the example provided, the high side of a tapped transformer is most likely within the zone of protection of the line relaying. If so, the line relaying is planned to protect this area and so its operation would not be considered a Misoperation. The SDT will add an example that covers this situation in the Guidelines and Technical Basis section of the draft standard. 4. The SDT modified the definition of Misoperation based on your comment. The SDT removed the phrase "such as power swings, under-voltage, over excitation or loss of excitation" from the category. There is no need to specifically indicate that a Protection System failure could be the cause for this category as a Protection System failure could cause failure to trips, slow trips and unnecessary trips during Faults.		
Westar Energy	No	1. "Unnecessary Trip - Other than fault" is not clear if an impedance-based transmission line Protection System trip in response to an unstable (or stable) power swing is a Misoperation. 2. "Failure to trip" as described in the Application Guidelines should have the reference to "within the time normally expected" removed as this would be addressed in "Slow Trip".
Response: Thank you for your comments. 1. A line impedance relay (set as intended) that trips for a power swing that entered the relay's characteristic for its set times is not a Misoperation. If incorrectly set, then it would be a Misoperation. 2. The phrase "within the time normally expected" is proper as used in the Application Guidelines and is not meant to address the "Slow Trip" categories.		
Georgia Transmission Corporation	No	1. Failure to operate as designed: a) The protection system failed to operate for a fault within the designated zone of protection. b) The protection system failed to protect a designated BES component from a system abnormality as designed. Operating external to design parameters: a) The protection system operated with no fault condition present. b) The protection system interrupted power to a BES component with no system abnormality present. 2. Slow Trip (as defined) is difficult to measure without "smart relays" or fault recorders or sequence of event recorders in every BES station. A high impedance fault will naturally cause slow clearing times and may indicate an out of zone trip when compared to a bolted fault.

Response: Thank you for your comments. 1. **The SDT started with the established categories of relay system misoperation developed by the IEEE Power System Relaying Committee Working Group I3. The "failure to operate" and "operating external to design parameters" categories are already covered under the failure to trip and unnecessary trip categories.** 2. **The SDT is neither mandating monitoring tools nor specifying how to investigate BES operations. The standard is being updated to make sure BES operations are analyzed to determine if the Protection System operated as designed and the BES reliability is thus maintained.**		
PacifiCorp	No	The proposal for a revised definition of "Misoperation" in the NERC Glossary of Terms includes five conditions. This definition is insufficient in the absence of considering such conditions in conjunction with the additional illustrative information offered in the "Guidelines and Technical Basis" (the "Guidelines") appended to the draft of PRC-004-3 for industry review and comment. PacifiCorp believes that the proposed revised definition of "Misoperation" should either be: (1) expanded to include additional technical information such as that included in the Guidelines; or (2) revised to expressly provide that the Guidelines, as appended to the standard, are incorporated by reference in the definition. The definition of "Misoperation," if included in the NERC Glossary of Terms as presently proposed is not sufficiently robust for the purpose of registered entities properly identifying and addressing all Protection System Misoperations within their respective systems.
Response: Thank you for your comment. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.**		
NextEra Energy, Inc.	No	NextEra Energy suggests modifying "Unnecessary Trip - Other Than Fault" to: Any Protection System operation in the absence of a fault or for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.
Response: Thank you for your comment. **The category of "Unnecessary Trip - Other Than Fault" has been modified to be more inclusive.**		
Southern Company	No	The definition is acceptable; however, the following recommendations are provided to clarify the Guidelines and Technical Basis for the definition. 1. Failure to Trip - During Fault: The reference to the time in which a Protection System is normally expected to operate introduces aspects of a slow trip into the discussion of failure

		to trip. To avoid confusion between failure to trip and slow trip, the second sentence should be revised as follows: "If a fault or abnormal condition is cleared by at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation." 2. Slow Trip: The TPL standards require that the system is designed to meet performance requirements specified in TPL-001 through TPL-004, but does not require any specific remedy to assure that the requirements are met. Suggest referring to high-speed performance in the context of meeting the performance requirements in place of high-speed performance required by the TPL standards. The sentence should be revised as follows: "Delayed fault clearing caused by a failure of an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems." 3. Unnecessary Trip - During Fault: Clarify that while operation of the backup system is not a Misoperation, that failure of the protection for the adjacent zone is a Misoperation. The Note should be revised as follows: "Operation of properly coordinated backup Protection System relays to clear the fault in an adjacent zone is not a Misoperation of that backup system if the protection for the adjacent zone fails to clear the fault within the specified time. However, the failure of the Protection System for the adjacent zone is a Misoperation." 4. Unnecessary Trip - Other Than Fault: The description for this part of the definition lacks clarity as to whether operation of an impedance-based transmission line Protection System in response to a power swing is a Misoperation. The description should be modified to provide clarity on this issue.

Response: Thank you for your comments.

1. Your proposed change to "Failure to Trip - During Fault" in the Guidelines while helping to separate this category from that of "Slow Trip" does not indicate that that the Fault was properly cleared by the combined Protection Systems of the Faulted Element. Your suggestion indicates that the Fault clearing absolves it from being a Misoperation even though it could have been associated with a "Slow Trip" type of Misoperation. The definition of Failure to Trip – During Fault has been enhanced to include reference to overall performance of a Protection System.

2. The definition of Slow Trip was updated to reflect your comments about performance.

3. Your proposed changes to "Unnecessary Trip - During Fault" have been incorporated in the definition.

4. The non-fault conditions listed in this category of the standard has been eliminated. Changes to the Guidelines and Technical Basis section regarding "Unnecessary Trip - Other Than Fault" have been made for clarity. Four examples are

provided in the Guidelines and Technical Basis section including one specifically on power swings.		
Flathead Electric Cooperative, Inc.	No	The definition should be specific to Transmission or BES Misoperations
Response: Thank you for your comment. **Glossary definitions have no assigned applicability. The standard's Applicability (Functional Entities and Facilities) section specifies the applicability to the BES.**		
Green Country Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes that that the NERC Glossary definition of Misoperation must coincide exactly with the one used by the ERO-Reliability Assessment and Performance Analysis (RAPA) Group. Although the differences are minor, the two processes need to seamlessly flow together so that data needs and reporting templates do not diverge.
Response: Thank you for your comment. **The work of the RAPA Group on Misoperation reporting was considered as input to the standard drafting effort. The SDT is revising PRC-004-2a; PRC-004-3 will further refine the definition and reporting requirements.**		
Oncor Electric Delivery	Yes	
Private Citizen	No	The definition of a Misoperation no longer includes an exclusion for maintenance activities. Is this intended? While I certainly agree that human errors can cause serious disturbances - for instance the Florida event in 2008 - these events also present lots of challenges to correct. There can be labor issues, disciplinary issues, and a general problem of what CAP to take when the field person says "I knew better. I just screwed up." So, I wanted to know if the drafting team had explicitly considered this topic and chose to include it as a Misoperation going forward.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		

Consolidated Edison Co. of NY, Inc.	No	1. The fifth category "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, "... unrelated to on-site maintenance and testing activity". 2. The new definition only addressed "Slow Trip". Many times, "Fast Trip" could cause Misoperation as well. We suggest that the new definition should include "Fast Trip".
Response: Thank you for your comments. **1. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. A "Fast Trip" is not by itself a Misoperation except perhaps when you are considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System's zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an "Unnecessary trip - during Fault." This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.**		
Orange and Rockland Utilities, Inc.	No	The new definition only addressed "Slow Trip". Many times, "Fast Trip" could cause Misoperation as well. We suggest that the new definition should include "Fast Trip".
Response: Thank you for your comment. **A "Fast Trip" is not by itself a Misoperation except perhaps when you are considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System's zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an "Unnecessary trip - during Fault." This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.**		
PSE	Yes	
TransAlta	No	To add item 6. Unnecessary Trip - Other than Fault - any Protection System Operation for non-fault conditions such as current sensing device failure, voltage sensing device failure,

		DC/AC control circuit/device failure.
Response: Thank you for your comment. **The category "Unnecessary Trip - Other than Fault" already existed and has been modified to incorporate comments received.**		
Entergy Services	No	The definition of Misoperation as proposed in the definition section of the standard needs more detail. In particular, with regard to "Failure to Trip - During Fault", Protection System communication aided schemes which are not essential to meet NERC Planning Standards should be excluded from the definition of Misoperation. An entity that voluntarily exceeds NERC requirements by applying communication aided schemes with more rigor than is required by standards should not be exposed to additional compliance consequences as a result of exceeding those standards. The revised Misoperation definition should specifically include such exception in the actual standard definition and NERC Glossary. In particular, the definition of Misoperation should be changed as follows: Failure to Trip - During Fault - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. Protection System communication aided schemes which are not essential to meet NERC Planning Standards are excluded from this definition.
Response: Thank you for your comment. **This category of the definition has been modified based on comments received.**		
GenOn Energy	No	1. In the numerous locations used in the definition, replace "Any" with "A" 2. Definition should incorporate the following exclusions: A. Misoperations from human intervention during maintenance activities B. Failure of a relay control function or protective function not associated with protection of the BES or a BES element, i.e. a microprocessor relay serving multiple functions including, but not exclusively, BES Protection. C. Misoperations resulting from the effects of a disaster upon the Protection System components, i.e. a hurricane, tornado, fire, or flood destroys a substation control house.
Response: Thank you for your comments. **1. The SDT modified the definition as you suggested.** **2. A. The SDT has modified the definition based on comments. Language has been added to the proposed definition that**		

reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities." B. The SDT agrees with the comment and modified the language in the Applicability section and Guidelines and Technical Basis section to reflect it. Control functions within relays are not included in the review of Protection System operations for identifying Misoperations. C. The SDT believes you cannot include exclusions for natural disasters in the definition without distorting the intended purpose.		
Indiana Municipal Power Agency	No	1. IMPA has serious concerns that the proposed definition of "Misoperation", including the list of conditions in Draft #1 dated June 9, 2011 (page 12/16) is broad and far reaching and could potentially include equipment not currently defined as Protection System equipment. For example, (3) includes "Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect" could be interpreted to include high voltage circuit breakers - if a breaker operates (trips) slower than intended (for example in 20 cycles instead of the factory stated 5 cycles) then this could potentially be termed a "Misoperation". By default this would expand the scope of PRC-005 to include additional equipment not currently covered in PRC-005. 2. In addition the Misoperation Categories listed in the drop-down box for Misoperation Category on the Quarterly Misoperation Reporting Form are even less detailed and could be interpreted differently and broader than the proposed definitions themselves. 3. In addition there seems to be an extraordinary amount of effort in PRC-004-3 to lay blame for an operation (now termed "Misoperation") on operating/maintenance/engineering personnel leaving the reporting utility open for damages because of "errors". Utilities have and always will use good faith efforts and follow prudent utility practices when operating their utility. The goal of any utility is to minimize outages/customer interruptions - with PRC-004-3 we are now opening ourselves up to fines for lack of compliance and potential lawsuits should personnel "miss" a setting. Additional causes listed include in the definitions tab on the spreadsheet include, for instance, under Communications failures, Telco errors resulting in the mal-performance of communications over leased lines. Once a leased line leaves the utility's premises they have NO control over that circuit - it is the property of the Telco. If a TELCO technician lifts a bridge clip at a CO on a protection circuit then the utility could potentially be held responsible for a Misoperation. IMPA had no objections with the current definition of Misoperation and feels the proposed definition should stay consistent with current definition.
Response: Thank you for your comments.		

1. **Incorrect functioning of equipment not included in the Protection System definition (e.g. breakers) does not fit into the classification of a Misoperation.** 2. **The Misoperation Categories listed in the drop-down box for Misoperation Category on the Quarterly Misoperation Reporting Form are titles that are defined in the definition.** 3. **The purpose of the standard is not to blame individuals for Misoperations but to set up requirements to identify and correct the causes of Misoperations in order to improve the reliability of the BES. It would be negligent of the industry to ignore the human factor as a contributor. In the example of a telecommunication company (TELCO) error causing a Misoperation, the electric utility is responsible for identifying that the Misoperation was due to a TELCO problem, follow up with TELCO to ensure the problem is fixed, consider whether any other corrective actions need to be taken and implement the corrective actions if applicable.**		
Exelon	Yes	1. The definitions are fairly generic but there are additional qualifications in the Application Guidelines. See #3 Slow Trip definitions versus Application Guidelines # 3, this could lead to inconsistent applications. 2. ComEd: Suggest including language regarding human performance events. Is the intent of bullet #5, on page 3, to excluded human performance events as with the previous definition?
Response: Thank you for your comments. 1. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.** 2. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Manitoba Hydro	No	Item 3 (Slow Trip) in the definition of 'Misoperation' should be clarified by replacing the word 'planned' with 'specified'.
Response: Thank you for your comment. **The SDT replaced the word "planned" with "intended" based on other comments.**		
Tacoma Power	Yes	Yes, the proposed definition is reasonable, provided that protection system operations resulting from maintenance, testing, or similar inadvertent activities are excluded, as is the case with the existing definition. Alternatively, the proposed definition is reasonable if under R1.3, "a declaration explaining why there is no need to develop a CAP" is

		acceptable.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Ameren	No	Please 1) show the present Misoperation definition so that entities can see how much SDT is proposing to change it. 2) The entire 3rd bullet item (excluding on-site maintenance caused) of the existing definition needs to be retained in your proposed definition items 2 and 5; 3) clarify in item 3 'Slow Trip' by adding 'slower than required to meet TPL requirements' as the SPCS intended; 4) explain in the Background section that "a Protection System" is an element's protection in its entirety (e.g. for a transmission line, it would typically consist of both the primary and secondary protection designed to protect the line) and provide such an example; and, 5) remove 'power swings' from items 2 and 5 'Other Than Fault' examples because it is pre-mature to include until after protective relay response during power swings is addressed in Phase 3 of Project 2010-13.
Response: Thank you for your comments. **1. The existing definition is listed in the Background section. The definition was extensively rewritten; so, a red-lined version would be confusing.** **2. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **3. The reference to "delayed" clearing in the Application Guidelines refers to specific situations when high-speed clearing is not required to meet TPL standards. However, even if high-speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). The SDT has modified the definition of Misoperation based on comments. The word "planned" has been replaced with "intended". Information in the Guidelines on "Delayed Fault Clearing" has been incorporated in the definition.** **4. The definition of Misoperation has been modified and addresses your concern.** **5. The project referenced addresses loadability of relays during stable power swings. The SDT agrees that "power swings" does not need to be mentioned in category 5 (now category 6); however, it should remain in category 2. For example, if a power swing enters an impedance characteristic of a relay that is intended to trip for such a power swing,**		

its failure to operate would be a Misoperation.		
Utility Services, Inc.	No	Utility Services disagrees with the addition of incorrect settings to the definition of a Misoperation (Cause Code in Table 2 of the White Paper). Misoperations imply that there was an action or inaction based upon the equipment not performing. It is our view that incorrect settings are maintenance and testing function, not a Misoperation. Utility Services is NOT suggesting that we ignore incorrect settings of these devices. I believe that incorrect settings should be dealt with in the PRC-005 standard instead. As a part of regular maintenance and or testing, the settings should be validated and affirmed by the entity. A Misoperation is when a device fails to act or acts inappropriately. Finding out at the time of the Misoperation that the settings are incorrect are not the right time to determine this. The better standard of reliability for these devices is to do it before they misoperated. If the M&T routines are validating the settings on a regular basis, then the discovery/re-correction will actually benefit reliability because they will be corrected prior to any so-called Misoperation.
Response: Thank you for your comment. **An incorrect relay setting can be the cause of a Misoperation and should be corrected whenever found. Incorrect settings are not always found by the maintenance and testing function; for example, if a setting was incorrectly calculated, the error would most likely not be discovered by maintenance and testing.**		
American Electric Power	No	It would appear that the proposed definition is overly broad, when compared to the application guidelines specified on page 12. For example, going strictly by the criteria on page 3, one might unnecessarily report a Misoperation when it would not be considered such according to the guidelines. Employee action, during on-site maintenance and testing or commissioning activities, that directly initiates an unintentional operation should not be included in this category. However, for example, if an employee leaves trip test switches or cut-off switches in an inappropriate position following maintenance and testing or commissioning activities and a system fault or condition causes a Misoperation, this would be counted as a Misoperation.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
American Transmission Company, LLC	No	The definition of Unnecessary Trip - During Fault should be changed to "Any Protection System operation that causes a circuit breaker/switcher to trip for a Fault not within the

		zone it is designed to protect." The definition for Unnecessary Trip - Other Than Fault should be changed to "Any Protection System operation that causes a circuit breaker/switcher to trip for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate."
Response: Thank you for your comment. **The proposed definition was meant to generalize the operation function. The SDT believes the Misoperation categories "Unnecessary Trip" implies that an interrupting device has operated.**		
CenterPoint Energy	No	The proposed revision to the definition of Misoperation includes conditions that are found in the Guidelines and Technical Basis in PRC-004-3, but not in the definition itself. CenterPoint Energy recommends that the conditions be included in the formal definition, instead of in a separate document. Should this recommendation not be accepted, as an alternative, the following statement should be added to each of the five items in the definition of Misoperation: "For specific conditions, refer to the Guidelines and Technical Basis in PRC-004-3 Reliability Standard."
Response: Thank you for your comment. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.**		
BGE	No	Item #5 Unnecessary Trip - Other than Fault The Misoperation definition included in the Misoperation reporting template includes the caveat "an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable Misoperation. This should be carried through the definition as well.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Consumers Energy	No	This definition is much better than the current definition. However, the Unnecessary Trip - Other Than Fault should specifically exclude operations during on-site activities.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads**		

"and is unrelated to on-site maintenance, testing, construction or commissioning activities."		
ITC	Yes	
Wisconsin Electric	No	The 5th category, "Unnecessary Trip - Other Than Fault", should also include an exception for trips which occur during onsite testing or maintenance work on the associated protection system. This exception is in the existing definition, and we maintain it should remain in the new definition. This is needed to allow exceptions for trips which may occur during commissioning or when making modifications due to the complexity of modern protection and control schemes.
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Duke Energy	No	1. On #2 "Failure to Trip - Other Than Fault", need to add the word "abnormal" before the word "non-Fault" in order to exclude normal non-Fault situations such as where protective relays are used for control functions (i.e. reverse power relays on generators). 2. On #4 "Unnecessary Trip - During Fault", need to replace the phrase "not within the zone it is designed to protect" with the phrase "for which the Protection System is not intended to operate". The current wording would not require reporting of unnecessary trips for a fault within the zone the Protection System is designed to protect. For example, we use over-reaching protection for breaker failure protection. 3. On #5 "Unnecessary Trip - Other Than Fault", it should be made clear where failed relays would be reported. For clarity, add the phrase "or any other normal system condition" after the phrase "loss of excitation".
Response: Thank you for your comments. **1. The SDT disagrees with the comment as abnormal in this case is a subjective term. Verbiage has been added to the "Guidelines and Technical Basis" section to provide clarity on the issue and to exempt control function operations from being classified as a Misoperation (whether or not the control function is performed within a protective relay).** **2. The SDT has modified the definition, as you suggested.** **3. The SDT modified the definition of Misoperation. The SDT removed the phrase "such as power swings, under-voltage, over excitation or loss of excitation" from the category. There is no need to specifically indicate that a Protection**		

System failure could be the cause for this category as a Protection System failure could cause failure to trips, slow trips and unnecessary trips during Faults.		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The definition language is not clear on failures due to human intervention. For example when TO testing in a switchyard causes a GO trip, is that a Misoperation?
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Springfield Utility Board		
BC Hydro	Yes	

- An exclusion to the category "Unnecessary Trip – During Fault" was added to the definition related to the proper remote Protection System operation.
- Comments related to "Fast Trip" were not incorporated because the SDT believes that this type of Misoperation is included in the category "Unnecessary Trip – During Fault".
- Comments related to exclusion of incorrect settings or other design flaws not being a Misoperation were not incorporated because these fit within one of the established causes of relay system Misoperation developed by the IEEE Power System Relaying Committee Working Group I3.
- Comments related to inclusion of the entirety of breakers within the reporting of Misoperations were not included because the mechanical portion of a breaker is not part of a Protection System.

2. **In Requirement R1.1, the team is requiring the identification of all Misoperations. Do you agree that Requirement R1.1 is sufficient to identify Misoperations? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The principle comments covered:

- The ambiguity concerning the scope of Misoperations. The SDT modified the requirements and clarified that Misoperations were limited to those components of Protection System(s) owned by the entity.
- The entire scope of Protection System operations need to be reviewed to determine if a Misoperation has occurred. The SDT clarified that review of Protection System operations was not associated with control functions of relays. The SDT also clarified that the classification of Protection System operations as a Misoperation does not include the individual components of the Protection System, if the Protection System, as a whole, operated correctly.
- The applicability of the requirements to the Distribution Provider and Generator Owner and the applicability of Protection Systems, whether BES or non-BES. The SDT referenced the Applicability section which specified the entities to which the requirements applied, and that the requirements only applied to Protection System(s) of Facilities that are a part of the BES.
- Concerns about the Misoperations procedure and its implementation. The requirement to have and implement a procedure has been eliminated.
- The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 “Compliance Monitoring and Assessment Processes” of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	This item refers to Part 1.1.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment.		
Public Service Enterprise Group Company	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Ass'n - System Protection	No	The term “detailed” is too vague and should be eliminated. See comments to the “Measures.”
Response: Thank you for your comments. **The SDT agrees and has removed the word ”detailed” from the standard. See the SDT response to your comments regarding Measures in Question 5.**		
FirstEnergy	No	1. We do not believe that 1.1.1 (Document and review all BES Faults and BES Protection System operations.) should apply to GO as written, even though R1 indicates it would. We realize that the Glossary definition of BES includes generation resources, but as 1.1.1 is written, it implies that it's referring to the transmission system. 2. Regarding the phrase “within its system" at the end of R1, we ask that this be clarified by changing the phrase to “within its area of ownership or control”. 3. We ask that the requirements to “have” and “implement” a Misoperations procedure be separated. We suggest removing the word “implement” from R1 and creating a separate R2. 4. Furthermore, see our answer to Question 4 regarding VRF.
Response: Thank you for your comments. 1. **Part 1.1.1 has been deleted and Requirements revised to remove the ambiguity relating to applicability to Generator Owners. The text in the requirements now refers to the Misoperations of the entity’s Protection System(s).** 2. **The phrase “within its area of ownership or control” of the Protection System could introduce an inadvertent reliability gap such as when instrument transformer windings are shared. By modifying the text as requested the team is concerned that the owner of the instrument transformer will expect the owner of the relay fed by the instrument**		

Organization	Yes or No	Question 2 Comment
transformer to provide the appropriate documentation. The application of the standard is by default limited to the Protection System(s) owned by the entity. The text has been revised to refer to the Misoperations of the entity's Protection System(s). 3. The standard has been revised to state what an entity must do to find and resolve Misoperations. The requirement to have and implement a procedure has been eliminated. 4. See our response in Question 4.		
Pepco Holdings Inc Affiliates	No	Requirement R1 should be modified to read "Each Transmission Owner, Generation Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protective System Misoperations within its system." The term BES was omitted from R1. We feel the term BES should appear in both R1, as well as R1.1.1, since this requirement is applicable only to protective systems associated with the BES.
Response: Thank you for your comment. The standard has been revised to eliminate the use of the term 'BES' in the requirements. BES is mentioned in the Applicability section of the Standard.		
Southern Company Generation	No	We believe that too many details are included in the existing Requirement R1. It is not necessary to be so specific on the documentation process. A high level requirement is much more appropriate. With so many details regarding the investigation compositional elements, valuable attention to resolving the operation/mis-operation is diverted to record keeping. Keep in mind that a large utility may have several relay operations per week, and requiring specific time tabling for each requirement with varying start dates for the magnitude of relay operations makes the proposed approach quite burdensome. It is not necessary to have a written relay operation investigation methodology in order to investigate all relay operation. Requiring a program document is not an essential component of reviewing operations and executing corrective action if they are needed. Please consider changing the existing lengthy requirement that, in our opinion, has far too many detailed requirements with the following three requirements which match the objectives of the current draft on page 5 of the PRC-004-3 draft standard dated 09 Jun 2011 (Draft #1). R1: Review all Protection System operations on the BES and identify those that are BES Protection System Misoperations. R2: Analyze BES Protection System Misoperations to determine the cause(s). R3: Where appropriate, implement Corrective Action Plans to address the cause(s) of the BES Protection System Misoperation. The

Organization	Yes or No	Question 2 Comment
		requirements do not need to be any more complicated that these. The accompanying measures to match these requirements can be: M1: Documentation proving that all (BES Protection System) operations were reviewed. M2: Documentation of analyses to determine cause(s) of the mis-operation. M3: Documentation of all Corrective Action Plans (problem resolution) resulting from misoperations. Revising the requirements to match the objectives listed provides an effective, simply stated standard for identifying and correcting Protection System Misoperations.
Response: Thank you for your comments. **The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. Want to be clear that the wording in R1 and in section R1.1.2 refer to the BES and not all Misoperations. 1. 2. Would like to see BES included in R1 between address all BES protection system Misoperations. Also would like BES added to Section 1.1.2 for clarity. 2. 3. We would ask that this requirement be broken up to address identification, corrective action, and reporting. This would give you greater flexibility to create different VRF and VSLs for each piece that is being addressed. 3. 4. We feel that making an administrative action, such as completing a report, a high on the VRFs and VSLs isn't justified.
Response: Thank you for your comments. 1. The language in the requirements has been revised to refer to the Misoperations of the entity's Protection System. 2. The Applicability Section specifically states, "Protection Systems for Facilities that are part of the BES." 3. The standard has been revised to separate these items into different requirements. The SDT explored using either a standard		

Organization	Yes or No	Question 2 Comment
		requirement or a Section 1600 data request for Misoperation(s) reporting. At this time, the SDT feels the appropriate place in the standard for Misoperation(s) reporting is section 1.4 Additional Compliance Information. 4. The Violation Risk Factors have been revised.
MRO's NERC Standards Review Forum	No	1. This requirement is overly prescriptive and unnecessary. The requirements (and its parts) should not prescribe how entities should comply, but address the "what" is to be accomplished within this requirement. NERC Reliability Standards should specify simple actions such as: 1) that the applicable entities should have a procedure for identifying all BES protection system misoperation on BES protection systems installed for detecting faults on BES elements, 2) implement corrective actions for identified systemic causes of BES protection system Misoperations, 3) document those actions, and 4) report all BES Misoperations to their regional entity on a quarterly basis. This is a better way to meet the goal to require the identification of all BES protection systems installed for detecting faults on BES elements. Simply have a plan, implement the plan when warranted, document what the entity accomplished and report quarterly to the applicable Region. The misoperation report could also be used by NERC and the applicable Region for trending of Misoperations. 2. It is recommended that the SDT align this project with the NERC Functional model. 3. The reference to its system implies operations when it's more like the equipment it owns, please clarify. 4. R1 also uses the word "all" with Protection System Misoperations. Since the SDT has defined 5 different attributes of what a Misoperation is, this would require every function of a relay to have 5 areas that "identify and address" the associated Misoperation. If an entity's relay has 15 functions associated with it, they will need to identify up to 75 ways of identifying and addressing the Misoperation. Note that Protection System is clearly defined and has 5 components to it. So the 75 ways to identify and address the Misoperation will also need 4 more (not five since relays are used as the example). 5. Recommend that the SDT rewrite R1 to read: Each TO, GO, and DP shall have and implement when required, a procedure to identify and address the Misoperation of a BES Protection System within its metered boundaries. 6. Recommend that the SDT add a requirement 2 that fulfils the section 1.4 additional compliance information concerning quarterly reporting.

Organization	Yes or No	Question 2 Comment
		7. Requirement 1.1.1 should be for BES Protection System Misoperations not all operations. The use of the word "all" BES Protection System operations seems unreasonable and un-necessary. Exceptions need to be allowed e.g., acts of god, storms, etc. This requirement is overly burdensome for those individuals involved in restoration. (Certain relays lose information once they are reset.) The NSRF recommends that that this requirement be removed altogether unless further clarified.
Response: Thank you for your comments. 1. The SDT has modified the standard to reduce the detail of the documented process for all processes associated with Misoperations. 2. It is not clear from your comment what aspect of the standard fails to be aligned with the NERC Functional Model. 3. The language in the requirements has been modified to refer to the Misoperations of the entity's Protection System. 4. The definition has been revised to address your comment. The phrase, "Failure of a Protection System to operate as intended," was added. 5. The standard has been revised to separate the documented process and the implementation of the process. In reference to the "when required" action, specific time frames are necessary to ensure a measureable and enforceable requirement. The language in the requirements has been revised to refer to the Misoperations of the entity's Protection System. 6. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information". 7. The SDT has modified the standard to require the Registered Entity to develop a process that ensures each operation of its Protection System(s) is reviewed for Misoperations. To determine all Misoperations, all Protection System operations must be reviewed with a systematic approach. The Guidelines and Technical Basis section of the standard includes the following statement regarding extenuating circumstances: "In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard."		
Electric Market Policy	Yes	1. Dominion suggests R1 to read "Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protection System Misoperations within its system." While the purpose statement

Organization	Yes or No	Question 2 Comment
		indicates that is the intent of the standard, we believe the inclusion of BES in the first sentence of R1 will avoid questions as to whether this standard applies to ALL Protection System Misoperations (including those that are not designed to protect the BES). 2. Recommend changing (R.1.1.1) to state "Document and review all BES Faults and BES Element operations. (R1.) Lists in the requirement that entities must identify and address all Protection System Misoperations. To do this you must either have a Fault or Element to operate to initiate the process. 3. Having the Violation Risk Factor listed in the brackets under (R1.) only adds confusion to the Requirement. In (R1.), only list those specific items that are required according to the new standard and remove the reference to the Violation Risk Factor. The VRF and VSL information should be in a separate dedicated section and not in the requirement section.
Response: Thank you for your comments. **1. The language of the requirement has been revised. The Applicability section specifically limits facilities to the Protection Systems of BES facilities.** **2. The Misoperations of the Protection System may be the result of faults on a Facility other than a BES facility. The SDT has modified the standard to require the Registered Entity to ensure each operation of its Protection System(s) is reviewed for Misoperations.** **3. This is the standard NERC format for Reliability Standards. The VRFs and VSLs are also provided in a separate section of the Reliability Standard named 'Table of Compliance Elements'.**		
Pacific Northwest Small Public Power Utility Comment Group	No	1. Please see our answer to Q1. 2. Slow tripping events that went according to "plan" are not identified as Misoperations even though the result may not have been intended. 3. Slow or failed breaker operations are also not identified as Misoperations.
Response: Thank you for your comments. 1. **The definition of Misoperation is only for Protection Systems; the entirety of breakers is not included in the definition of Protection Systems. This is not meant to minimize the importance of interrupting devices, but to narrow the targeted area of review, analysis, and corrective actions.**		

Organization	Yes or No	Question 2 Comment
2. **The SDT added the following language to the definition of Misoperation to address your comment: "Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect." Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.** 3. **The entirety of a breaker is not considered a part of a Protection System. Please see the Guidelines and Technical Basis section.**		
LG&E and KU Energy	No	1. Much more than Misoperations is required in R1.1.1. A) The GO/DP would not have knowledge of BES faults outside the boundaries of GO or DP, and this requirement should only involve the TO; B) Reporting correctly operating equipment will not increase the reliability of the BES system. 2. Any operator-initiated action or normal/expected operation of relays should not require documentation when the goal of this standard appears to be about "Misoperations". Having to document/investigate correct operation will delay performing required actions to bring a unit on-line to support the BES system.
Response: Thank you for your comments. 1. **A) The SDT has modified R1 to require the Registered Entity to ensure each operation of its Protection System(s) is reviewed for Misoperations.** **B) While Entities are not required to report correct operations, it is understood that the Entities need to have evidence that each Protection System operation has been reviewed.** 2. **The requirement language has been revised. The Standard has been revised to require review of each Protection System operation. There is no requirement to document operator-initiated actions in this standard.**		
APM Members	No	1. While R1 is sufficient to identify Misoperations, there are several issues with the requirements. In R1, use of Protection System as a description with Misoperations is redundant. The proposed definition of Misoperations includes Protection System. 2. While we understand Part 4.2.1 of the Applicability section limits the applicability of the standard to Facilities that are part of the BES, we are concerned that the applicability section could be overlooked. Thus, we suggest the language ("Distribution Provider that owns a BES Protection System") from the previous version of the standard be

Organization	Yes or No	Question 2 Comment
		incorporated into the requirements. 3. The language of the "within its system" should be replaced with "on its equipment". The Generation Owner, Transmission Owner and Distribution Providers don't have systems in the traditional sense. They own parts of the System. "On its equipment" should be appended to the end of Part 1.1.1. Otherwise, the part could be inadvertently interpreted as applying to every BES Fault and BES Protection System regardless of equipment ownership. For example, TO A might have to evaluate a Fault on TO B's equipment. Clearly, this is not the intent. 4. The second bullet under Part 1.2 and the bullet under Part 1.4 are redundant. Both require the registered entity to identify additional steps for an investigation.
Response: Thank you for your comments. 1. **Since the term "Misoperations" is defined as applicable to a Protection System, which is also a defined term, the language has been revised to remove the term Protection System in front of Misoperations.** 2. **The Applicability Section is a formal part of the Reliability Standard. Adding the additional statement would create redundancy.** 3. **The text has been revised to refer to the Misoperations of the entity's Protection System.** 4. **The standard has been revised.**		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Bonneville Power Administration	No	1. BPA feels that R1.1 is ambiguous. 2. In R1.1.1, what does it mean to document and review a BES fault? 3. In R1.1.2, identify and document all Misoperations associated to what? 4. In R1.1.3, BPA believes the word "address" is ambiguous.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
1. The standard has been revised in an attempt to remove ambiguity. 2. The reference to BES Faults has been removed. 3. The standard has been revised. Misoperations are associated with an entity's Protection System operations. 4. The word "address" is no longer used.		
Western Area Power Administration	Yes	
Westar Energy	No	The requirement should be specific to BES Misoperations.
Response: Thank you for your comment. **The term Misoperations only applies to Protection Systems which are limited in the Applicability section of the standard to 'Protection Systems for Facilities that are a part of the BES'.**		
Georgia Transmission Corporation	No	R.1.1.2 is extraneous. If R1.1.1 is adhered to, all Misoperations will be identified and documented.
Response: Thank you for your comment. **The standard has been revised.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	
Southern Company	Yes	
Flathead Electric Cooperative, Inc.	No	1.1.2 & 3 should be specific to BES Misoperations
Response: Thank you for your comment. **The term Misoperations only applies to Protection Systems which are limited in the Applicability section of the standard to**		

Organization	Yes or No	Question 2 Comment
'Protection Systems for Facilities that are a part of the BES'.		
Green Country Energy	No	1. My concerns surround sub requirement 1.1 and 1.1.1. First concern is 1.1 the word detailed is too subjective of a term to be audited in my opinion. I would suggest replacing it with "step by step". 2. Second concern is 1.1.1 "Document and review "all" BES Faults and BES Protection System operations."It does not address that protection system operations occur daily in a cycling combined cycle possibly other generation plants too. As an example the steam turbine is brought offline using the reverse power relay. That is a BES protection system operation. I would suggest language that allows documentation of expected "normal operations" and secondly exempting those expected operations from the "document and review" requirement.
Response: Thank you for your comments. **1. The standard has been revised. The word "detailed" is no longer used.** **2. If the reverse power relay is used exclusively for control then it is not considered part of the Protection System. If the reverse power relay doubles for protection and control, review of the relay operation would be necessary when an unexpected operation occurs.**		
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	No	There needs to be a tight correlation with the Misoperation cause codes already introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place. Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up - with unique data requirements and reporting templates.
Response: Thank you for your comments. **The SDT has been coordinating with the ERO-RAPA group. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was**		

Organization	Yes or No	Question 2 Comment
appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 “Compliance Monitoring and Assessment Processes” of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".		
Oncor Electric Delivery	Yes	
Private Citizen	No	In R1.1.1, the drafting team calls for all BES faults and operations to be documented and reviewed. Why? Presumably, the drafting team is concerned that Misoperations can go undetected and that the opportunity to learn from - and avoid that SECOND Misoperation - would be lost. However, in the Guidelines and Technical Basis found on page 12 of 16, the drafting team proceeds to define certain protection system "failures" (my term) as not being a Misoperation. For instance, the failure of a redundant Protection System when another Protection System operates correctly or the failure of a communication scheme when TPL standards were not violated. Conceptually, this makes no sense. Either you are worried about undetected Misoperations or you are not. But you cannot have it both ways. Imho (in my honest opinion, so my grand kids tell me, you should write the investigation requirements like this. One must investigate to see if a Misoperation occurred when: a) the operation of any current interrupting device (i.e. breaker) by relay action for a fault not in its primary zone of protection, b) the operation of any circuit interrupting device by relay action when no fault occurred, c) when equipment damage due to a fault condition occurs but no Protection System operated. The wording can be improved, but I believe you can get the idea. If the drafting team believes it must have all operations analyzed, then it must remove the exemptions in the Guidelines and Technical Basis, as these are inconsistent with analyzing all operations for Misoperations.
Response: Thank you for your comment. **The standard has been revised; the reference to Faults has been removed. The SDT believes a review of all Protection System operations is necessary to determine Misoperations. The Guidelines and Technical Basis section of the standard has been modified to be more aligned with the definition of Misoperation. The revised definition is consistent with the NERC System Protection and Control Subcommittee proposed definition of Misoperation.**		
Consolidated Edison Co. of	Yes	By selecting “Yes”, we assume “R1” mentioned here is really “R1.1”.

Organization	Yes or No	Question 2 Comment
NY, Inc.		
Response: Thank you for your comment about the typographical errors on the comment form.		
Orange and Rockland Utilities, Inc.	Yes	By selecting “Yes”, we assume “R1” mentioned here is really “R1.1”.
Response: Thank you for your comment about the typographical errors on the comment form.		
PSE	Yes	
TransAlta	Yes	
Entergy Services	Yes	
GenOn Energy		
Indiana Municipal Power Agency	No	In its current proposed format R1 requires that ALL operations have to be reviewed and documented for determination of a possible “Misoperation”. Examples given as a “Misoperation” in the spreadsheet included a failed secondary potential breaker (see 1. above - PRC-004-3 greatly expands the equipment utilities must now test on a regular basis). IMPA feels that R1 goes above and beyond a good faith effort to identify a true protection system misoperation. In addition the process of documenting and reporting requirements are onerous and time consuming and could potentially become costly in terms of the dollars required to prove an operation was not a misoperation and in terms of the manpower required to oversee this effort. The BES is a dynamic system that undergoes changes continuously - for a utility to have the ability to foresee all of these real-time changes, anticipate the effect that these changes will have on their protection systems and eliminate all Misoperations is not possible with today’s technology.
Response: Thank you for your comment. **The details in the requirements are needed to ensure they are measureable and enforceable. To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach.**		

Organization	Yes or No	Question 2 Comment
Exelon	No	PECO: Similar to what Reliability First Corporation has created; PECO suggests that the five categories of Misoperations should be expanded to provide examples of what would constitute a misoperation vs. a non-misoperation for each of the categories. Exelon Nuclear: SERC Regional Criteria procedure for "Analysis and Reporting of Transmission and Generation Protection System Misoperations," currently includes guidance on misoperation categories and classifications and provides comprehensive examples of misoperation classifications. Such guidance has proved invaluable when determining if an event met the definition for reporting to the Region in accordance with PRC-004. It is strongly suggested that the NERC SDT provide similar guidance to registered entities to ensure timely and consistent reporting. ComEd: A formatting comment; the Requirement number formatting does not align with the questions in the comment form. Assuming question 2 referring to R1 items 1.1 - 1.1.3, question 3 is referring to Requirements R1.2, R1.3 and R1.4. TS&C: The requirement should not be to “have a procedure” The reliability objective should be to record, investigate and if required, develop corrective actions for mis operations. Suggest the Requirement read: R1. The Applicable Entity shall record, investigate and implement corrective action planning for all faults and Misoperations. R1.1 Record all BES faults and Protections System operations. R1.2. Complete an investigation and implement immediate corrective actions within 30 days. R1.3. Report Misoperations each quarter using the reporting template. R1.4. Complete a corrective action plan for each identified Misoperation. Requirements 1.2, 1.3 and 1.4 should be removed and replaced by one requirement. See suggested R1 above. Corrective Action Planning, Performance Improvement, Root Cause Analysis and Investigations are all standard business practices with widely accepted protocols and methodologies. The details concerning the possible outcomes of a CAP should be removed The standard requirements should not try to anticipate the possible outcomes, “cause not identified” and subsequent actions, “interim actions, final actions, timetables etc.” Nor should the standard include a statement requiring an entity to state that there is “no need to develop a CAP” or that “no further investigation is required”.

Response: Thank you for your comments.

PECO: The drafting team revised the definition of Misoperation to include more categories of Misoperations. There are

Organization	Yes or No	Question 2 Comment
examples of each category in the Guidelines and Technical Basis section of the standard. **Exelon Nuclear: The drafting team revised the definition of Misoperation to include more categories of Misoperations. There are examples of each category in the Guidelines and Technical Basis section of the standard.** **ComEd: The original comment form did have errors in reference. The standard has been revised.** **TS&C: The standard has been revised. The requirement to have and implement a procedure has been eliminated.**		
Manitoba Hydro	No	1. R1 should be clarified by changing '… and address all Protection System Misoperations within its system' to '… and address all Protection System Misoperations within its BES'. While the standard only applies to Protection Systems for Facilities that are part of the BES as stated in the Applicability Section, R1.1.1 explicitly states 'BES Faults' and 'BES Protection System operations' making R1 read like it refers to all Protection Misoperations in the Registered Entities' entire system. 2. R1.1.1 and M2 are too prescriptive and should not specify the process that a Registered Entity must follow to determine when a Protection System Misoperation has occurred. 3. R1.1.1 and M2 should only require a process to identify a list of all Protection System Misoperations rather than a list of every single fault and BES protection system operations on the Registered Entity's system.
Response: Thank you for your comments. **1. The application of the standard is by default limited to the Protection System(s) owned by the entity. The text has been revised to refer to the Misoperations of the entity's Protection System(s). The Applicability Section specifically states "Protection Systems for Facilities that are part of the BES".** **2. The details in the requirements are needed to ensure they are measureable and enforceable.** **3. To determine all Misoperations, all Protection System operations must be reviewed with a systematic approach.**		
Tacoma Power	Yes	None
Ameren	No	We assume you mean R1 and R1.1 here. Please 1) review and incorporate the Project 2009-17 interpretations that have been correctly incorporated in PRC-004-1a; the SDT should recognize PRC-004-1a in the Background section to provide correct history and continuity.

Organization	Yes or No	Question 2 Comment
		2) reword R1 to state: "Each ... and address its Protection System Misoperations." This removes 'all' because though we strive to find all it is impractical to guarantee all were found. The TO, GO, DP is responsible for the Protection Systems they each own, thus use 'its' and remove 'within its system' for clarity of responsibility. 3) Reword R1.1.1 to replace 'all' with 'its' for the same reasons as 2) above. 4) Reword R1.1.3 to insert 'identified' before Misoperation.
Response: Thank you for your comment. **We recognize there were typographical errors on the comment form.** **1. The mandatory and approved standard PRC-004-2a will be incorporated into this standard and will be recognized in the Background section.** **2. The standard has been revised.** **3. The standard has been revised.** **4. The standard has been revised.**		
Utility Services, Inc.	No	Please refer to our response to Question 1.
Response: Thank you for your comment.		
American Electric Power	No	1. We are confused by the numbering of the requirements in this question versus the numbering within the proposed standard. In addition, rather than developing additional sub-requirements and sub-sub-requirements which make it difficult to track compliance, we suggest discrete requirements which stand on their own. 2. Requirement R1 is not sufficient, because there are additional considerations set forth in the Standard's "Guidelines and Technical Basis section" regarding the identification of Misoperations. Requirement R1 should include a clear reference to the guidelines to lessen the possibility of confusion by an Entity or auditor. 3. 1.1.3 appears redundant with 1.2, as operations must be investigated in order to identify whether or not a misoperation has occurred. In addition, more detail is needed as to the exact intention of the word "address".

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. 1. We recognize there were typographical errors on the comment form. 2. The definition of Misoperation has been modified to be more aligned with the Guidelines and Technical Basis section of the standard. The revised definition is consistent with the NERC System Protection and Control Subcommittee proposed definition of Misoperation. 3. The standard has been revised; the word "address" has been removed.		
American Transmission Company, LLC	Yes	
CenterPoint Energy		
BGE	Yes	No comment.
Consumers Energy	No	Suggest removing the term "all" in R1 and R1.1.1 as the Standard should focus only on Misoperations and not evaluation of all operations.
Response: Thank you for your comment. To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach.		
ITC	No	1. Within 1.1.1 the wording "and BES Protection System operations" may be interpreted to include all components within a Protection System which could lead to a monumental task and is not necessary if no outage occurred. 2. 1.1.2 should be written to read simpler. Suggested changes: 1.1.1 Document and review all BES Faults or outages caused by BES Protection System operations.1.1.2 Identify and document all Misoperations.
Response: Thank you for your comments. 1. To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach. The revised Requirements deal with Protection System operations and not operation of components.		

Organization	Yes or No	Question 2 Comment
2. The standard has been revised.		
Wisconsin Electric	Yes	
Duke Energy	No	In the lead-in paragraph for R1, the word “all” should be replaced with “BES” for clarity. NOTE: R1.2, R1.3 and R1.4 are addressed in our response to question #3 below.
Response: Thank you for your comment. **The Applicability Section specifically states “Protection Systems for Facilities that are part of the BES”.**		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The documentation requirement under 1.1.1 is too broad and onerous. As an example, some generating units upon shut down may have lockout relays associated with opening the generator breaker. This technically is a protection system operation, but is working as designed. If that same generating unit were to cycle every day, then a report identifying the operation and classifying it as not a misoperation would need to be created every day. Therefore, requiring the documentation of all protection system operations is purely an administrative requirement. The burden of documentation does not encourage reliability and should be carefully considered as part of the standard.
Response: Thank you for your comment. **If the relay is used exclusively for control then it is not considered part of a Protection System. If the reverse power relay doubles for protection and control, review of the relay operation would be necessary when an unexpected operation occurs.**		
Springfield Utility Board		
BC Hydro	Yes	BC Hydro requests clarification for the unintentional protection system operation due to maintenance or testing. Is this unintentional operation considered a misoperation?
Response: Thank you for your comment. **Language has been added to the proposed definition that reads “and is unrelated to on-site maintenance, testing, construction or commissioning activities”.**		

3. **Requirements R1.2, R1.3, and R1.4 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with the allotted times? If not, please provide specific reasons why not and alternative recommendations.**

Summary Consideration:

Numerous commenters were concerned about the 90-day time limit associated with Requirement 1, Part 1.2 and its expected output; e.g., having completed the investigation including taking necessary outages. The SDT revised the standard by increasing the timelines and clarifying the steps involved to complete the investigation of a Misoperation.

Many commenters were confused about the starting point of the time intervals associated with the Misoperation investigation. The SDT has established the date of the Protection System operation as the reference point.

Other commenters were concerned about compliance with the standard after a natural disaster or significant system event. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "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…"

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	(This item actually refers to Parts 1.2, 1.3, and 1.4.) The Part 1.2 time interval of 90 days may not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages where they might be necessary. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although provision for this is made in Part 1.4, the language in Part 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation, which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation, and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either; the Corrective Action Plan when a**		

Organization	Yes or No	Question 3 Comment
cause was determined; or an action plan of additional steps if the investigation failed to determine a cause.		
Public Service Enterprise Group Company	Yes	Requirements R2, R3, and R4 do not exist. If R1-1.2, 1.3, and 1.4 are meant for comment, then the allotted times are agreeable with the following exception. 1. As 1.4 is written it sounds like even after investigating for 90 days and not being able to find a cause for the misoperation, an action plan is needed to continue looking for the cause. The intent of the action plan in 1.4 (as indicated in the second and third full paragraphs on page 15) is not to conclusively determine a cause, but to take actions that may further a future investigation should another misoperation occur. The wording of 1.4 should be revised to reflect the true intent. 2. We suggest changing 90 days in R1.2 to 180 days, and changing 120 days in R1.4 to 210 days (180 +30). In certain cases, root causes may not be able to be fully evaluated in 90 days because lines may need to be removed from service to do so, and clearances may not be granted within the 90-day window. By extending the time frame to 180 days, the time needed for removing lines from service for root cause determination will be sufficient in virtually all cases, thereby eliminating the burden for Corrective Action Plans and the associated requirements of such plans. 3. The first sentence of Section 1.4 should also be changed to read "Within 60 days following June 30 and December 31," and in Attachment 1 the title "Quarterly" should be changed to "Semi-Annual." 4. Other suggestions: Change the second bullet in R1.2 so that it directly refers to R1.4. 5. Also, make R1.2 language "past' tense to be consistent with R1.3 and R1.4.
Response: The SDT thanks you for your comments. 1. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. 2. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent		

Organization	Yes or No	Question 3 Comment
documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. 3. The drafting team chose to retain Quarterly reporting. 4. The SDT revised the standard. 5. The SDT revised the standard.		
Hydro One	No	(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
Tri-State Generation and Transmission Ass'n - System Protection	Yes	The limits for those parts are acceptable (though, as we comment in 4. below, we believe the parts should be individual requirements).
Response: The SDT thanks you for your comment. The SDT revised the standard.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	No	1. Various testing or investigating recommendations may require BES equipment be taken out of service to accomplish the appropriate testing and investigation involved with relay Misoperations. This testing may dictate what CAP is appropriate. The time limits stated do not provide any exceptions for equipment which cannot be taken out of service within the time limits identified for operational concerns or when these equipment outages are cancelled by operations based on system integrity concerns. There should be some exceptions for these instances.R1.2 prescribes 90 days to investigate the misoperation. 2. Compliance section 1.4 prescribes 60 days following the end of each calendar quarter to provide periodic data submittal. This timing will create a situation where the last month of the reporting time period will not yet be due for completion of the original investigation. We suggest the compliance section 1.4 agree with the 90 day investigation period so that all original investigations are completed at the time of the data submittal.
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** 2. **The drafting team retained the current time frames for reporting.**		
Pepco Holdings Inc Affiliates	No	**1.** The 90 day window to conduct an investigation and identify the cause of a protective system misoperation is not practical in many situations and unreasonable. Outage windows for transmission facilities are highly dependent on weather and system loading conditions and as such are usually relegated to only a relatively few months during the Spring and Fall. Also, during these mild weather / low load times any outage request submitted to investigate a protective system misoperation is competing with numerous other construction related outage requests being evaluated by the Transmission Operator for TPL infrastructure upgrades in addition to other

Organization	Yes or No	Question 3 Comment
		facility maintenance outages. The Transmission Operator typically requires a minimum 30 day lead time for scheduling outages on BES facilities. Granting of these outages is the sole responsibility of the Transmission Operator, not the Transmission Owner. Canceling of the outage by the Transmission Operator may require the Transmission Owner to go through the 30 day re-submittal process. Denial of an outage request by the Transmission Operator could delay the misoperation investigation and force the Transmission Owner to be in non-compliance. An emergency outage could be declared to enable a misoperation investigation to take place, but depending on loading and system conditions, the facility forced outage could result in an increased reliability risk to the system, and/or the need to run expensive off cost generation. Declaration of an emergency outage should rarely be used, only for those instances of very high risk.In summary, it is not practical in many situations or reasonable to expect the Transmission Owner to be responsible to investigate the cause of a misoperation within 90 days when they have no control over the outage scheduling and approval process. As such, both the 90 and 120 day time frames should be removed entirely from the standard (i.e., structure the requirements similar to existing PRC-004-1 & PRC-004-2). Alternatively, but not recommended, would be to develop time frames only for those activities over which the Transmission Owner has full control. This second approach would of course require an extensive rewrite of Requirements R1.2, R1.3 and R1.4 and would in the end contribute little to improving the timeliness of investigations, since the majority of the time consumed in the investigation process is waiting for outages to be granted. For example, a requirement could be established that “within 45 days of the date of each identified misoperation launch an investigation into the cause and submit an outage request for any facility outages as necessary for diagnostic testing.” These tasks are within the Transmission Owners control. However, completion of the investigation cannot be bounded since the outage process is indeterminate and out of the control of the Transmission Owner. **2.** Similarly, since the development of the corrective action plan is dependent on completing the investigation (which is outage dependent), development of the CAP cannot be bounded either. Because of this it is recommended that all time frames be removed.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
1. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The standard allows for extended investigation periods in Requirement R4. **2. The CAP is developed after the investigation is completed and the cause determined.**		
Southern Company Generation	No	There are no requirements R2, R3, and R4 in the 09 Jun 2011 Draft #1 posted in the "Standards Under Development" NERC web site. Responding to these actions as written in R1.2, R1,3, and R1.4 of the draft standard, we believe that specifying so many deadlines for individual tasks will make the identification, investigation, analysis process too cumbersome. The periodic reporting requirements to the regional entity requires continuing attention to these tasks and is sufficient to ensure their completion.
Response: The SDT thanks you for your comment. **The SDT revised the standard. Timelines are included in the standard to ensure entities have clearly identifiable targets in investigating and correcting a Misoperation. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable. Periodic reporting requirements to the Regional Entities cannot sufficiently achieve the reliability objectives of the Standard.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	We don’t agree with placing a timeframe on the investigation of a misoperation. There is an inconsistency with section 1.2 of the application guidelines and section 1.2 of R1. One states that its 90 days from the identification of the misoperation and the other states from the date that the misoperation occurred. If it’s the case that the 90 days start from the occurrence of the misoperation we are concerned that putting a timeframe on the analysis would cause detriment analysis especially during system wide event I.E hurricane. Could cause hundreds of operations and would need a longer analysis timeframe for these. Could add a process by which the entity could file for extension

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>during these extraordinary circumstances. Was the intent for the timeframes to start after the misoperation was identified or was the intent to start the clock after the operation occurs? In the question it should have read R1.2, 1.3, 1.4 rather than R2, R3, R4.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment.

The SDT revised the standard based on your comment. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: “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.”</td></tr>
<tr><td>MRO's NERC Standards Review Forum</td><td>No</td><td>We agree with the time tables/time lines if a bullet is added to allow the Regional Entity to grant the registered entity an extension beyond the 90 days within R1.2 and beyond the 120 days within R1.3 and R1.4.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment.

The SDT revised the standard and believes the new timeframes in the standard are sufficient.</td></tr>
<tr><td>Electric Market Policy</td><td>No</td><td>Question states R2, R3, and R4. Assume the question is referring to (R1.2), (R1.3), and (R1.4)?

1. (R1.3) and (R1.4) does not give appropriate time to gather data, run studies and perform field investigations for complex events where a Misoperation can occur. Recommend changing the 120 day requirement to 180 days.

2. Remove Box with “Rationale for R1”. It is not needed in the standard.

3. In (R1.2), (R1.3), (R1.4) and (R1.5) the requirement wording starts with “A requirement...”, recommend removing “A requirement that” in each section. Suggest wording change as follows: R1.2 The responsible entity shall within 90 calendar days of each identified Misoperation, investigate each Misoperation to determine its cause and do one of the following: R1.3 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was identified develop one of the following:R1.4 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was not identified develop one of the following:</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** 2. **The Rationale boxes are part of the new Results Based Standard Template. As noted in the "Definition of Terms Used in the Standard", once PRC-004-3 has received ballot approval, the Rationale boxes will be moved to the Application Guidelines Section of the standard.** 3. **The standard has been revised.**		
Pacific Northwest Small Public Power Utility Comment Group	No	While we realize many entities may want or need the structure presented, we can see situations where the cause would be immediately evident and can and should be rectified at the time of the initial site visit. The problem and corrective action would then be documented afterward. While the second bullet of 1.3 suggests this might be allowed, it is not explicitly so stated. In the name of reliability, shortcuts such as this should be explicitly allowed in order to avoid repeated identical Misoperations caused mainly by the standard process itself.
Response: The SDT thanks you for your comment. **In your example, if the corrective action is immediately completed then a CAP would be documented and the completion date indicated.**		
LG&E and KU Energy	No	We assume the SDT is referring to R1.2, R1.3, and R1.4 as there are no other requirements shown as R2, R3, and R4. Therefore, we have the following comment on R1.3:On Requirement R1.3, could the SDT clarify a little bit better that only a timetable and plans are needed to be completed within the 120 days, and not that the entire correction be completed within 120 days. Currently, R1.3 could be interpreted either way. Therefore, so that an auditor would not interpret it that the corrective action plan needs to be completed within 120 days, this needs to be clarified. Because GO's oftentimes have to wait to complete a corrective action plan until the next outage on a

Organization	Yes or No	Question 3 Comment
		unit, which would probably be greater than 120 days.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. New Requirement R3 does not indicate the CAP must be completed, only developed. New Requirement R4 requires completion of a CAP according to the work timetable. The entity has the ability to establish and revise the timeline for completion of its CAP or action plan.**		
APM Members		
PPL Generation	No	1. Requirement 1.2 states, "A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s)." This should be clarified to be “within 90 calendar days of identifying a Misoperation.” 2. Requirement 1.3 indicates within 120 days, the Registered Entity shall develop a CAP that includes “Final corrective or mitigating actions to reduce potential impacts to BES reliability.” This should be clarified to be “Final corrective or mitigating actions the Registered Entities plans to complete that reduce potential impacts to BES reliability.” It should be clear that not all “Final corrective or mitigating actions” need to be complete by the 120-day timeframe. Also, as suggested above, the language “within 120 calendar days” should be clarified to be “within 120 calendar days of identifying a Misoperation.”
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard for clarity.** 2. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection**		

Organization	Yes or No	Question 3 Comment
System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. New Requirement R2 does not indicate the CAP must be completed, only developed. New Requirement R4 requires completion of a CAP according to the work timetable. The entity has the ability to establish and revise the timeline for completion of its CAP or action plan.		
Florida Municipal Power Agency	No	see comments to Question 1
Response: The SDT thanks you for your comment. See our response to your comment in Question 10.		
Bonneville Power Administration	Yes	BPA believes the allotted time seems adequate.
Response: The SDT thanks you for your comment.		
Western Area Power Administration	Yes	
Westar Energy	No	1. Requirements R1.2, R1.3, and R1.4 introduce time limits. The requirements need additional clarification on the timeframes. Are the timeframes from when the operation occurs or from when the operation is determined to be a Misoperation? 2. Exemptions to the established timeframes should be available in cases of large scale events. 3. R1.2 - remove the requirement to document causes that were ruled out, overly burdensome and unnecessary. 4. R1.3 - Remove the reference or specifically define what constitutes a declaration. 5. R1.4 - remove or refine, overly burdensome and unnecessary. 6. R1.5 - remove, vague and unnecessary.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard for clarity.** 2. **The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "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."** 3. **The SDT revised the standard.** 4. **A declaration in regards to the requirements of this standard is a statement explaining why you did not need a CAP or why no further actions will be taken. The SDT is not specifying the format of a declaration.** 5. **The SDT revised the standard. Timelines are included in the standard to ensure entities have clearly identifiable targets in investigating and correcting a Misoperation. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable.** 6. **The SDT revised the standard, but disagrees with your comment. Completion of the CAP or action plan is necessary to correct the causes of Misoperations.**		
Georgia Transmission Corporation	Yes	Agreed in principle, however the question should be R1.2, R1.3 and R1.4. Not R2, R3, R4.
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	(Refers to Requirements R1.2, R1.3 & R1.4)
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
Southern Company	No	The 90 day and 120 day periods are acceptable; however, the start of the 90 day and 120 day periods requires clarification that time is measured from the "date of occurrence of

Organization	Yes or No	Question 3 Comment
		each identified Misoperation."
Response: The SDT thanks you for your comment. **The SDT revised the standard for clarity.**		
Flathead Electric Cooperative, Inc.	Yes	
Green Country Energy	Yes	Just a comment for possible exceptions. When gathering data from manufacturers the 90day time frame can be aggressive. e.g. (GE) some language added to allow for information gathering time outside of the entities control would be helpful.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration believes that 90 days is generally enough to assess a Misoperation - or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The 120 day corrective action plan time frame is acceptable to us as well.
Response: The SDT thanks you for your comment.		
Oncor Electric Delivery	Yes	
Private Citizen	No	See my comments on Question 9.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. **See our answer to your comments in Question 9.**		
Consolidated Edison Co. of NY, Inc.	No	(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Orange and Rockland Utilities, Inc.	Yes	By selecting "Yes", we assume "R2, R3, and R4" mentioned here are actually "R1.2, R1.3, and R1.4" due to there are no R2, R3, and R4 in this new version (3).
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
PSE	Yes	
TransAlta	No	There are no requirements R2, R3 and R4 on PRC-004-3
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		

Organization	Yes or No	Question 3 Comment
Entergy Services	No	For Misoperation corrective action plans which could require out of budget cycle funding, significant project coordination with other groups or entities, and/or require major outage considerations, 120 calendar days is too aggressive to meet a corrective action plan development requirement which includes “final corrective or mitigating actions.....”. We suggest the timing for R1.3 and R1.4 be 120 days following the completion of R1.2. Therefore, we suggest the wording for R1.3 and R1.4 be revised to:1.3 A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following: 1.4 A requirement that for all Misoperations for which the cause(s) was (were) not identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following:
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
GenOn Energy	No	The intent is understood: to promote timely investigations and responses. However, the allotted times assumes that scheduling outages for investigation, testing, or maintenance are easy to obtain in every instance. 90 days is insufficient time for seasonal periods lasting five or six months or more.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		

Organization	Yes or No	Question 3 Comment
Indiana Municipal Power Agency	No	The times as listed are aggressive, especially for smaller utilities that have facilities whose loss would have minimal impact on the BES. It may be more appropriate to break the time limits into different categories, such as operations (and Misoperations) that impact critical facilities versus those operations that impact facilities that are not critical to the BES. For instance the time limits listed should apply only to critical facilities. For non-critical facilities the times should be extended to 180 days from the date of a Misoperation to complete the investigation and 240 days to develop a plan or otherwise address the Misoperation.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The SDT believes the time interval is sufficient to establish a suspected cause, or plan further steps for the investigation. This standard is applicable to BES facilities as listed in the Applicability section.**		
Exelon	Yes	PECO: **1.** Time limits are reasonable; however, the drafting team should consider requests for extensions based on extenuating circumstances, i.e. emergent work/storm related issues, etc., related to R1.2, R1.3, and R1.4. **2.** It is not clear what the deferral reference on page 15 of 16 of the Application Guidelines refers to. It appears to allude to a deferral process for CAPs but this is not specifically identified in R1.5 of the standard. ComEd: For R1.3, is there an intended limit on the work time table? Coordinating mitigating actions between customer premises or other entities can extend corrective plans significantly. Exelon Nuclear: Time limits are reasonable; however, the SDT should strongly consider a provision for those events where the root cause of a Misoperation may be dependent on an external investigation (e.g., a relay may have to be examined by the manufacturer in an attempt to determine a defect). The timeline associated with forensics performed by

Organization	Yes or No	Question 3 Comment
		an external company are outside the control of the registered entity.
Response: The SDT thanks you for your comments. **PECO** **1. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "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."** **2. The standard has been revised. New Requirement R4, Part 4.2: "Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion".** **ComEd** **The work timetable needs to reflect mitigating measures as a result of the Misoperation; depending on the scope of the corrective action it is impossible to generally impose such time limits on the work plan.** **Exelon Nuclear** **The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Manitoba Hydro	Yes	
Tacoma Power	No	The Guidelines and Technical Basis section asserts that the 90 and 120 day timeframes "provide sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes." For some responsible entities, this period arguably could approach 6 months (180 days). Exacerbating this issue is the fact that the VSL increases rapidly after the 90 and 120 day timeframes are exceeded. While identification, analysis, and correction of protection system mis-operations is important to reliability of the BES, the responsible entity should be granted greater latitude to triage investigations based upon the perceived severity of

Organization	Yes or No	Question 3 Comment
		the nature of the mis-operation with respect to other operational constraints. Not all mis-operations are equal in potential impact. Investigating a mis-operation should not degrade system reliability in the name of compliance, and the 90 and 120 day timeframes may result in undue hurried response for some, less critical mis-operations.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The SDT believes the timelines provide sufficient latitude for the entity to prioritize Misoperation response.**		
Ameren	No	**1.** We don't see R2, R3, and R4 in the posted document; We assume the SDT mean R1.2, 1.3 and 1.4. **2.** From our perspective, the SDT rationale for R1 is flawed. Using the posted TADS 2008 and 2009 reports, Failed Protection System Equipment is only responsible for 1.1% of the hours of AC Circuit Sustained Outages and ranks as the 9th Cause Code. Considering the large number of sustained outages, even larger number of momentary outages, and huge number of non-outage hours in which the Protection System correctly restrained, the Protection System is extremely reliable across a wide range of conditions and numerous challenges. We agree that Misoperations should be investigated and corrective actions taken if a reasonable cause is found, but the importance of this issue is being overstated. **3.** In R1.2, please replace '90 calendar days' with 'six calendar months' to allow sufficient investigation time in non-peaking periods because BES equipment outages are needed for a fair number of investigations. **4.** In R1., please restate as " A requirement that for each Misoperation for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days of the cause being identified per R1.2, develop one of the following ..." because the Corrective Action Plan cannot be developed until after the cause is identified. **5.** R1.4 also needs to be 120 days subsequent to initial field investigation of R1.2, similar

Organization	Yes or No	Question 3 Comment
		to R1.3, and replace 'all' with 'each'.
Response: The SDT thanks you for your comments. 1. **We recognize there were typographical errors on the comment form.** 2. **The majority of Protection System operations are correct. However PRC-004-3 is intended to address Protection System Misoperations on the BES. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable. The activity of identifying and mitigating these Misoperations is essential to maintaining reliability of the BES.** 3. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** 4. **The SDT revised the standard.** 5. **The SDT revised the standard.**		
Utility Services, Inc.		
American Electric Power	No	**1.** There is no R2, R3, and R4 in the current draft of the standard. **2.** Also, the process needs to accommodate for the later identification of a misoperation after new information is obtained. Some investigations might take a month after an event occurs before that event could or would be declared a misoperation.
Response: The SDT thanks you for your comments. 1. **We recognize there were typographical errors on the comment form.** 2. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause**		

Organization	Yes or No	Question 3 Comment
is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
American Transmission Company, LLC	No	What about wide scale events such as the 2003 blackout? There does not appear to be an exception. ATC suggests that a provision be made to allow for declaration of an extension of the timelines identified in requirements R1.2, R1.3 and R1.4 in the case of a wide scale system event (NERC event categories 4 or 5).
Response: The SDT thanks you for your comment. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "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."		
CenterPoint Energy		
BGE	No	R1.2 through R1.4 require the registered entity to complete various phases of a misoperation investigation by specific times. In general the times are generous enough to comply with, but the fact is many investigations require transmission facility outages that must be approved by the Transmission Operator, and these may not be granted. To meet the timeline set forth in the Requirements the Registered Entity may have to declare an emergency outage and accrue the expense of running off cost generation. While this requirement is seemingly reasonable, it unreasonably holds compliance by the Registered Entity hostage to the entities who have no "skin in the game".
Response: The SDT thanks you for your comment. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		

Organization	Yes or No	Question 3 Comment
Consumers Energy	No	The time limits should be from the date of identification of a Misoperation and not the date of the Misoperation. This will allow for the time required to gather information from the field to determine if a Misoperation has actually occurred.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
ITC	No	Because of coordination to shutdown the associated equipment, the time to investigate may exceed the time limit of 90 calendar days following the misoperation.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Wisconsin Electric	Yes	1. The second bullet under R1.2 is unnecessary given R1.4. 2. Also, replace “timetable” with “schedule” in 1.3, 1.4, and 1.5. 3. The “…was (were) …” references in R1.3 and R1.4 should be replaced with the plural case alone for clarity. E.g, “…for all Misoperations for which the causes were identified.”
Response: The SDT thanks you for your comments. **1. The SDT revised the standard.** **2. The use of the word “timetable” is consistent with the NERC Glossary definition of a Corrective Action Plan (CAP).**		

Organization	Yes or No	Question 3 Comment
3. The SDT revised the standard.		
Duke Energy	No	1. R1.2 - replace the phrase “identified Misoperation” with the phrase “Protection System Operation” to clarify that the clock starts with the Protection System Operation, not when you identify a Misoperation. 2. Also replace the phrase “investigate the Misoperation” with the phrase “analyze any Misoperation”. 3. R1.2 first bullet - Reword as follows: “For each Misoperation where the cause(s) are identified, document the analysis and the cause(s) determined.” 4. R1.2 - Increase the time to 120 calendar days and note under the second bullet that where a transmission or generation outage is required to complete an analysis (i.e. nuclear switchyard), it’s permissible to document that as additional steps planned to identify the cause(s). 5. R1.2 second bullet - Change the word “investigation” to “analysis”. 6. R1.3 - Change 120 to 60 calendar days, and replace the phrase “of the Misoperation’ with the phrase “of completing the analysis in R1.2”. 7. R1.4 - Delete R1.4 because it is redundant to parts of R1.2 and R1.3 8. R1.5 - Modify R1.5 so that a Registered Entity can revise its CAP or action plan as outlined in its timetable, in order to deal with changes in outage schedules, etc.
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard.** 2. **The SDT revised the standard.** 3. **The SDT revised the standard.** 4. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine**		

Organization	Yes or No	Question 3 Comment
a cause. 5. The SDT revised the standard. The SDT believes the word "investigate" is a more comprehensive term that includes "analysis", and we believe is a more appropriate word for the requirement. 6. The SDT revised the standard. 7. The SDT revised the standard. 8. The SDT revised the standard.		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The "no" response is due to confusion in the question. We suspect that the requirements intended for reference were R1.2, R1.3 and R1.4. The time allotments seem reasonable.
Response: The SDT thanks you for your comment. We recognize there were typographical errors on the comment form.		
Springfield Utility Board		
BC Hydro	Yes	

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

Summary Consideration:

1. Many commenters suggested dividing Requirement R1 into several requirements so that the VRFs could be set at different levels, rather than 'High' for all of the Parts of the old Requirement R1. The drafting team agreed and separated Requirement R1 into four requirements with appropriate VRFs and VSLs.
2. Many commenters believed the VSL matrix was too complex. Separating the single requirement into four requirements resolved this issue.
3. Many commenters questioned the VSL assignments. The drafting team included new VSLs to reflect the new requirements.
4. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".
5. One commenter wanted the "Operations Planning" Time Horizon removed but the SDT believes the Time Horizons are appropriate for each of the new requirements.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Many factors affect power system reliability, and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation,**		

Organization	Yes or No	Question 4 Comment
investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
Public Service Enterprise Group Company	No	Setting the VRF as HIGH seems to indicate there is no time to waste in finding and correcting the cause of the misoperation, yet 90 days are allowed currently to investigate, and another 30 days are allowed to develop a Corrective Action Plan, for which there is no timeframe given for completing other than to document a timeframe and abide by it. Because of this long timeframe in the standard as currently drafted, a VRF of MEDIUM is appropriate.
Response: Thank you for your comment. The drafting team agrees with your comment in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
Hydro One	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
Tri-State Generation and Transmission Ass'n - System Protection	No	The Requirement R1 should be split into several requirements with individual VRFs and VSLs. For example, the Measure associated with Requirement R1, Part 1.1 is primarily administrative in nature and should not have a “High” VRF.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
FirstEnergy	No	We do not agree with a HIGH VRF for the sole requirement in the proposed standard. We believe that not having a procedure for handling Misoperations is much less of a risk to reliability than the actual reporting of the Misoperations. We suggest that having a procedure requirement be assigned a LOW VRF, and the requirement to implement be assigned a "MEDIUM" VRF. Since this standard pertains to after-the-fact reporting, there is no immediate risk to the BES and none of the requirements therefore warrant a HIGH VRF.
Response: Thank you for your comment. **The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Pepco Holdings Inc Affiliates	No	Most of the VSL's are related to the time frames with which the misoperation investigation is completed, or the corrective action plan developed. Both of these are completely dependent on the availability of outages to perform diagnostic testing to determine the cause of the misoperation. As described extensively in Question #3 the Transmission Owner cannot be held responsible to complete these tasks within a specified time frame when they have no control over the outage scheduling and approval process. 1. Compliance should be judged on whether all BES events were reviewed, an investigation conducted and a corrective action plan developed and implemented. Not whether these activities were completed within some arbitrarily chosen time frame. 2. Compliance could also be judged on the timeliness and completeness of the quarterly data submittal mentioned in section C1.4 of the standard.
Response: Thank you for your comments. **1. The drafting team has assigned VSLs in accordance with FERCs June 19, 2008 Order on Violation Severity Levels, as well as NERCs VSL guidelines. The drafting team extended the timeframes in the standard based on industry comments. The drafting team believes it is important to meet the established timeframes and has set the VSLs appropriately.** **2. The SDT agrees with your comment.**		

Organization	Yes or No	Question 4 Comment
Southern Company Generation	Yes	The VRF needs to be high as is specified in the draft. The magnitude of the components that make up the VSL matrix in the proposed draft #1 is indicative of the excessively prescriptive composition. The requirements, measures, and violation severity levels need to be simplified as described in the comment to question 2 above.
Response: Thank you for your comments. **The drafting team has assigned VSLs in accordance with FERCs June 19, 2008 Order on Violation Severity Levels, as well as NERCs VSL guidelines.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	See comment in question two.
Response: Thank you for your comment. **See our response in Question 2.**		
MRO's NERC Standards Review Forum	No	The VSLs are incorrect. 1. All documentation time frame references should be deleted. 2. If they are retained the VRF for R1 should be dropped to lower as the requirement is now administrative documentation. Documentation does not affect the electrical state or capability of the bulk electric system. The non documentation items under the severe VSLs can be modified to fit the moderate, high, and severe categories as follows: Moderate: The responsible entity did not identify all protection system Misoperations High: The responsible entity did not investigate all identified protection system Misoperations Severe: The responsible entity did not have a procedure to address protection system Misoperations OR the responsible entity did not implement a plan to correct any Misoperations.
Response: Thank you for your comments. **1. The drafting team has retained the timeframe references because they are used to ensure that all operations are**		

Organization	Yes or No	Question 4 Comment
examined and that all Misoperations are discovered and action plans are developed in a timely manner. 2. The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
Electric Market Policy	No	Adjust the VSL time horizons and Application Guidelines to reflect a change in (R1.3) and (R1.4) from 120 days to 180 days.
Response: Thank you for your comment. The VSLs and time horizons are based on the new requirements.		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members	No	1. We disagree that the VRF is consistent with other Reliability Standards. The SDT cites the need to deviate from the Medium VRF assigned to the similar requirement of EOP-004-1 R2 because it does not include implementation of corrective actions after the analysis. We disagree with this assessment as there is an implied obligation to implement any recommendations from analysis done to comply with EOP-004-1 R2. NERC investigative and enforcement personnel have routinely expected implementation of corrective actions from investigations. Thus, for consistency (as required by FERC Guideline 3), the VRF for PRC-004-3 R1 should be Medium. 2. We disagree with inclusion of Operations Planning in the Time Horizon. This is a backwards looking analysis. While it does correct for forward looking operations, it is not intended for planning but to simply correct an operational issue. Otherwise, Operations Assessment should be eliminated as a category as the purpose of looking backwards is to correct operations going forward and another category would always be selected along with Operations Assessment. 3. Any late completion of the CAP results in a High VSL. The drafting team should consider graduated steps based on the lateness of completion. Missing the CAP completion work timetable by a few days is not nearly as big a violation as missing the CAP work timetable by

Organization	Yes or No	Question 4 Comment
		months. 4. The second to last High VSL expands upon the requirement by mentioning delivery dates which would violate FERC Guideline 3 for VSLs. The requirements establish that a work timetable must be established. A timetable could be based on quarters rather than specific dates. If specific dates are desired, the requirement should be fine tuned to make this clear. 5. Several of the VSLs mention a “declaration”. These VSLs should be expanded to match the language of the requirement more closely for clarity.
Response: Thank you for your comments. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The standard has been revised and the Time Horizons have been established for the new individual requirements. Time Horizons correspond to the period of time it could take to mitigate a violation of the requirement.** **3. The drafting team modified the VSLs.** **4. The drafting team modified the VSLs.** **5. The separation of the requirements and the new VSLs clarify the usage of the term “declaration,” which is used in the requirements.**		
PPL Generation		
Florida Municipal Power Agency	No	See comments to Question 1.
Response: Thank you for your comment. **See our response to your comment in Question 1.**		
Bonneville Power Administration		
Western Area Power		

Organization	Yes or No	Question 4 Comment
Administration		
Westar Energy	No	
Georgia Transmission Corporation	Yes	
PacifiCorp		No comments.
NextEra Energy, Inc.	No	NextEra Energy thinks there should be flexibility with Corrective Action Plans (CAPs) and action plans. CAPs and action plans will involve steps that are prepared at a time when all relevant information is not available. As such, there may be a need to modify the CAPs and action plans as additional information becomes available. (See proposed text for Requirement R1.3 and R1.4 in the response for question 9 below.)
Response: Thank you for your comments. **The drafting team made modifications in the new Requirement R4 to add the flexibility to update a CAP.**		
Southern Company		Not Applicable
Flathead Electric Cooperative, Inc.	No	
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP does not believe that a Severe VSL is appropriate if a Protection System operation with an obvious cause is not captured in a summary listing (R1.1 and M2). We understand the need for a rigorous review process, but in many cases, a thorough evaluation is just not needed.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team has revised the requirements but retained the requirement to review all operations in order to discover all Misoperations. New VRFs and VSLs have been assigned.**		
Oncor Electric Delivery	Yes	
Private Citizen		
Consolidated Edison Co. of NY, Inc.	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Orange and Rockland Utilities, Inc.	Yes	
PSE	Yes	
TransAlta	Yes	
Entergy Services	No	A single high VRF is too broad to be applied for all elements and geographical areas of the electrical system. Also, lower and moderate VSL assignments should be included for the corrective action plan completion timeline requirements.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
GenOn Energy	No	1. VRFs are worst-case one-size fits all. The risk applied to a 500kV transmission line is the same applied to a radial connected 75 MW generating unit on a 138kV system. 2. The risk applied to the implementation of a corrective action plan is the same applied to post correction record keeping.
Response: Thank you for your comments. **1. The drafting team is following all the guidelines for assigning VRFs. Risk applied to the criticality of individual Facilities is not a part of the VRF assignment.** **2. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Indiana Municipal Power Agency	No	1. IMPA believes that all the sub-requirements should have their own individual VSL and VRF (similar to BAL-006-2). 2. When assigning VRFs and VSLs to the requirement and sub-requirements, the SDT needs to keep in mind the name of the standard is Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The title is NOT Analysis and Mitigation of Transmission and Generation Protection System Operations. The way the draft is currently written if one operation is missed and it is not documented and reviewed then an entity has violated a requirement with a high Violation Risk Factor and a severe Violation Severity Limit even if no misoperation has occurred.
Response: Thank you for your comment. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The drafting team has retained the requirement to document and review all operations in order to discover all Misoperations. The VRFs and VSLs have been modified.**		
Exelon	No	1. ComEd: For R1 VSL, not all potential actions can be identified based on ability to obtain outages associated with an investigation and many times an investigation start leads to

Organization	Yes or No	Question 4 Comment
		other paths. If an entity then creates generic all encompassing check list to meet the intent of R1, would they be held accountable to complete all the items listed when the cause was found at step 3 of 50 as an example. 2. Exelon Nuclear: Suggest rewording the VSL to state that "... either identified the cause or listed the preliminary actions planned to identify the cause ..." to address the concern that not all potential actions may be able to be identified within the required timeline.
Response: Thank you for your comments. **1. The requirement has been revised to identify and review all Protection System operations and designate each Protection System Misoperation. Once the cause of the Misoperation is identified, the entity should proceed to the development of the CAP. The VSLs are based on the new requirement.** **2. The drafting team has adjusted the VSLs to reflect the new requirement.**		
Manitoba Hydro	No	Manitoba Hydro suggests that the sub-requirements of R1 are split into separate requirements (e.g. R1, R2, R3, etc.) or each of the sub-requirements are assigned a separate VSL. The current VSL matrix is unclear.
Response: Thank you for your comment. **The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Tacoma Power	No	An automatic VSL of severe should not be assigned by failure to review one event. A VSL structure similar to draft 4 of PRC-005-2 is more reasonable. It seems reasonable that an entity should be penalized less severely if a lower percentage (1) of BES faults and BES Protection System operations have been documented and reviewed, (2) of Misoperations have been identified and documented, or (3) of Misoperations have been investigated and addressed. Part of the concern is that an entity may be heavily penalized for failing to identify a misoperation, based upon a later finding or a technicality, even if the entity has performed due diligence. Such a later finding may place an entity in a Severe VSL category, and a fear of such a scenario may cause an entity to devote an unreasonable amount of resources to develop or implement its procedure per this draft standard, particularly for arguably less severe Misoperations.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team has retained the requirement to document and review all operations in order to discover all Misoperations. The VRFs and VSLs have been modified.**		
Ameren	No	1) R1 VRF should be Low because the risk to BES reliability from one BES Fault or one BES Protection System operation not being documented and reviewed this very minute. The SDT itself alleges that up until now there are not even required Regional Entity procedures to support PRC-004-2, which would lead to numerous omissions in such regions. Operating as such under the proposed PRC-004-3 would lead to numerous High VRF and Severe VSL violations. One would expect a very unreliable BES over the past 4 years; however, the BES has been extremely reliable in this time frame. 2) The VSL need to be completely restated to recognize that a higher volume and BES voltage level >200kV Misoperations deserve a higher severity level, but fixing the number of days an entity is late at 90 days. For example, if an entity is unaware of one Misoperation on the <200kV, they'll end up missing all the deadlines; this belongs in the Lower VSL category. But one omitted Misoperation on the >200kV belongs in Moderate VSL. We propose <200kV omission quantities of 1, 2 to 4, 5 to 10, and >10 Misoperations in the Low, Moderate, High, and Severe VSL respectively. We propose >200kV omission quantities of 1, 2 to 4, and >4 Misoperations in the Moderate, High, and Severe VSL respectively. Similarly missing R1 deadlines by >90 days for identified Misoperations of the same number (1, 2 to 4, etc.) and voltage level would fall into our proposed VSL categories.
Response: Thank you for your comments. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The drafting team is following the guidelines for assigning VRFs. Risk applied to the criticality of individual Facilities is not a part of the VRF assignment. The VSLs are categorized based on the extent of non-compliance to a requirement.**		
Utility Services, Inc.		
American Electric Power	Yes	Though we agree overall with the VRFs, VSLs, and Time Horizons specified, the table seems more complex than necessary due to the number of "or" clauses involved. Should the sub-

Organization	Yes or No	Question 4 Comment
		requirements perhaps stand on their own as individual requirements?
Response: Thank you for your comment. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
American Transmission Company, LLC		
CenterPoint Energy		
BGE	No	The VSLs are tied to the timetables set out in Requirements R1.2 through R1.4. As stated before, this unreasonably holds the registered entity hostage to the whims of a Transmission Operator or other entity who at best may have “no skin in the game” and at worst may have competing priorities.
Response: Thank you for your comment. The time frames have been adjusted to allow for potential problems with outages. The new VSLs are based on the new time frames in the requirements.		
Consumers Energy		
ITC	No	Answered No because of issues with meeting present time limit.
Response: Thank you for your comment. The time frames have been adjusted to allow for more investigation if needed. The new VSLs are based on the new time frames in the requirements.		
Wisconsin Electric		
Duke Energy	No	VSLs should be revised consistent with our comments on the requirements.
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
The VSLs are based on the new time frames in the new requirements.		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board	No	SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect penalty funds.
Response: Thank you for your comment. **The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
BC Hydro		

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

Summary Consideration:

Several commenters proposed to make the reporting template the official document for compliance. The SDT responded that Attachment 1 reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.

Several commenters expressed concern that the use of the word "written" does not allow for electronic data retention. The SDT redrafted the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.

Several commenters expressed concern that the data retention period should not exceed the audit cycle. The SDT redrafted the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C, CMEP Section 3.1.4.2, which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended, and ending with the End Date for the Compliance Audit.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	1. Measure M2 requires additional documentation with no additional value. 2. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?

Response: Thank you for your comments.

1. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure the compliance with the requirements.**
2. **The "Quarterly Misoperations Reporting Data" table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**

Organization	Yes or No	Question 5 Comment
Public Service Enterprise Group Company	No	We recommend that R1.5, which is referenced in M6 and M7, be eliminated because the progress reporting of each CAP, including its completion, is sufficiently addressed in Section 1.4 (of the Compliance Monitoring Process section of the standard) which states "Each responsible entity will include the status of its Misoperation CAPS or action plans developed until these CAPs or action plans are reported complete." We note that Attachment 1, which defines the format of these periodic reports, allows an entity to enter CAP progress data beginning at the bottom of page 3 with corrective actions taken, and continuing on page 4 where CAP target and actual completion dates are reported. Evidence supporting those periodic reports could be requested as needed, and if necessary, the retention of evidence supporting the reports can be addressed in Section 1.2 of the Compliance Monitoring Process. With the elimination of R1.5, M6 and M7 can also be eliminated.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan.**		
Hydro One	No	1. Measure M2 requires additional documentation with no additional value. 2. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure the compliance with the requirements.** **2. The "Quarterly Misoperations Reporting Data" table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**		
Tri-State Generation and Transmission Ass'n - System	No	Measure M2 (and possibly others) is a Requirement. It does not improve reliability, but only provides for additional record keeping for compliance documentation.

Organization	Yes or No	Question 5 Comment
Protection		
Response: Thank you for your comment. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements.**		
FirstEnergy	No	Measure M7 - Since M6 already requires evidence to show implementation of the CAP as required by R1 subpart 1.5, we do not see the need to have M7 and suggest it be removed.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Pepco Holdings Inc Affiliates	No	The data retention provisions within the proposed standard seem reasonable. 1. However, there are concerns with several of the Measures.M2 - This measure should be re-written to state the entity shall “have evidence showing the dates of occurrence of all BES faults, associated protective system operations, and identified misoperations.” The standard should not specify the format that this data should be in. Some companies retain this data in their internal database format, or write detailed reports for each operation (both correct and incorrect). Specifying that a dated list be provided is unnecessary and non productive when other means of supplying the required evidence is available. 2. M4 & M5 - To avoid duplication of efforts and record keeping, the evidence required to satisfy these two measures should be included on the ERO spreadsheet. This way the review and feedback from the Compliance Monitor on the data supplied will be more timely than waiting for the next audit cycle, which may be years away. This would improve the overall objective of improving the thoroughness of the investigations and corrective action plans. Also, the ERO spreadsheet and this feedback from the Compliance Monitor could be used as evidence of compliance during a formal audit.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states that the examples of acceptable evidence "includes but is not limited to…" so it allows for flexibility in satisfying compliance with the requirement. This documentation is needed to ensure compliance with the requirements.** **2. The SDT revised the standard and Measure M4 now includes providing evidence for both the implementation and completion of CAPs and action plans. The data in the spreadsheet may not be complete evidence of implementing or completing a CAP or action plan.**		
Southern Company Generation	No	1. As noted above in the comment with Question 2, the Measures along with the Requirements should be phrased to establish the objectives only and not in the details of one possible way to accomplished the objectives. 2. Regarding the data (evidence) retention, what is the basis for the six year retention requirement? The data retention period needs to be the time elapsed since the previous audit unless directed by a Compliance Enforcement Authority to retain specific evidence for longer periods as part of an investigation. The Additional Compliance Information section (1.4) contains a requirement for the TO/GO/DP to report to the RE. This should be in the main requirement section of the standard. Also, to eliminate PRC-003, a requirement is needed for the RE to gather the region's records and report to NERC.
Response: Thank you for your comments. **1. The SDT revised the standard. The measures provide examples of evidence that can be used to demonstrate compliance with the requirements.** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 and requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. We would like to see in section M2 BES faults added here as well to clarify that we are talking about BES rather than any fault.

Organization	Yes or No	Question 5 Comment
		2. Should data retention follow the audit cycle for each applicable entity? I.E. if your audit cycle was three years then it would be three years and if it was six years then it would be the six years mentioned.
Response: Thank you for your comments. **1. The SDT removed BES Faults from the requirements because review of all Protection System operations would include Faults. The term BES is not used in the individual requirements and measures because the standard's Applicability section 4.2.1 states "Protection Systems for Facilities that are part of the BES."** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 and requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
MRO's NERC Standards Review Forum	No	1. The measures are incorrect and must be changed to match the modified requirements. However, the measures are reasonable and could be translated into requirements R1 - R6 or R1 - R7 with corresponding measures. 2. The data retention is incorrect. The data retention should state that data should be retained back to the last audit period. If not, the drafting team should provide the reliability reasoning why an entity with an audit cycle faster than six years would need to retain data past its last audit cycle. In 1.2 Evidence Retention, the "and Measures M1, M2, M3, M4, M5, M6, and M7" reference should be deleted.
Response: Thank you for your comments. **1. The SDT revised the standard. Each new requirement now has an associated measure.** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Electric Market Policy	No	Recommend removing Measures from (B.) and creating a separate section for Measures. (B.) should be changed to (B. Requirements) Also change to (C. Measures) (D. Compliance) (E. Regional Variances) (F. Interpretations) (G. Associated Documents) Suggest wording change as follows: C. MeasuresM1. The responsible entity shall have a current copy of its procedure for identifying and addressing Misoperations in accordance with Requirement R1.

Organization	Yes or No	Question 5 Comment
		M2. The responsible entity shall have documentation of Faults, BES Element operations, and identified Misoperations with their associated date of occurrence to demonstrate implementation of the processes related to Requirement R1, Part 1.1. M3. The responsible entity shall have documentation for each Misoperation investigation with their associated dates and either cause or where the cause of the Misoperation cannot be identified, any additional steps planned for identifying causes to demonstrate implementation of the processes related to Requirement R1, Part 1.2. M4. The responsible entity shall have documentation with associated dates of a CAP or an explanation of why there is no need to develop a CAP, for each Misoperation with an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.3.M5. The responsible entity shall have documentation with associated dates that includes a work timetable for implementation or an explanation of why no further investigation or actions will be taken for each Misoperation without an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.4. M6. The responsible entity shall have documentation with associated dates such as work management program records, work orders or other dated evidence, to demonstrate implementation of action plans related to Requirements R1, Part 1.5. M7. The responsible entity shall have documentation with associated dates that describes the manner in which the each CAP or action plan was completed to demonstrate compliance with the processes related to Requirements R1, Parts 1.5
Response: Thank you for your comments. **The SDT is following the NERC template for the new Results-based Standards where the requirements and associated measures are together rather than separated. The SDT has revised the draft standard.**		
Pacific Northwest Small Public Power Utility Comment Group	No	M6 and M7 appear to be duplicative. Please combine into a single measure, or more clearly state how they are different.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
APM Members	No	M1 is not consistent with the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC states that an entity may be held in violation of the requirement if it cannot produce previous versions of a procedure. Six years seems quite excessive for data retention. Three years should be sufficient. Six years appears to have been selected to match the audit cycle of the applicable functional entities. NERC contemplates that the data retention period may not be as long as the audit period in the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. Thus, it is not necessary for the date retention period to match the audit cycle.
Response: Thank you for your comment. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Bonneville Power Administration	No	1. BPA believes that under M1: Entities should not be required to provide documentation of the processes and procedures that they use to identify and address Misoperations. 2. M2 thru M7: BPA feels that the measures given are overly burdensome. Reading these measures would lead one to believe that NERC has an expert panel of protection engineers on standby, waiting to sift through the data provided for each misoperation, and give expert guidance to the industry. BPA feels that this is not accurate, as this NERC standard will only capture an overview of the number and types of Misoperations experienced in the industry. 3. BPA feels that the documentation requested will require many hours of work, and feels that the only review of it will be from an auditor whose only purpose is to make sure that it was accumulated. BPA feels that the burden of providing these detailed investigative reports and corrective action plans will result in less productive time for the individuals who

Organization	Yes or No	Question 5 Comment
		are the ones capable of solving the problems. BPA feels that only basic information, such as an elementary description of the misoperation, and a basic corrective action plan should be required. Lists of faults, investigative reports, work management program records, etc. seem to be unnecessary. If the experts at NERC need more information on a particular misoperation, they can always request it.
Response: Thank you for your comments. 1. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements.** 2. **Measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. The SDT revised the standard and each requirement now has an associated measure. The purpose of the draft standard is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.** 3. **The SDT believes the requirements are necessary to achieve the stated purpose of the standard.**		
Western Area Power Administration	No	1. M2 calls for a list of faults, protection system operations, etc. Would be good to be able to just point to our outage database instead of having to create a separate list. We are creating a separate spreadsheet at this point. 2. Six years for evidence retention seems kind of long. We would suggest 3 years or one audit period.
Response: Thank you for your comments. 1. **The SDT redrafted the standard. Measure M1 (old M2) now states that the examples of acceptable evidence "includes but is not limited to…" so it allows for flexibility in satisfying compliance with the requirement. This documentation is needed to ensure compliance with the requirements.** 2. **The SDT redrafted the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		

Organization	Yes or No	Question 5 Comment
Westar Energy	No	Data retention should coincide with the audit cycle.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Georgia Transmission Corporation	No	PRC-018-1 R5 DME data retention for RRO events is 3 years. 3 years should be adequate considering data is now available in spreadsheet format.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	
Southern Company		
Flathead Electric Cooperative, Inc.	Yes	
Green Country Energy	No	The term "written" keeps coming up and I feel it needs to be deleted since it has the connotation of a long hand "written" document and leaves no opportunity for an electronic format.
Response: Thank you for your comment. **The SDT revised the standard and the word “written” has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		

Organization	Yes or No	Question 5 Comment
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP	Yes	
Oncor Electric Delivery	Yes	
Private Citizen		
Consolidated Edison Co. of NY, Inc.	No	Measure M2 requires additional documentation with no additional value. Why would the “Quarterly Misoperations Reporting Data” table, in the format of the template provided with the standard, not be sufficient?
Response: Thank you for your comments. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements. The “Quarterly Misoperations Reporting Data” table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**		
Orange and Rockland Utilities, Inc.		
PSE	Yes	
TransAlta	Yes	
Entergy Services		
GenOn Energy		

Organization	Yes or No	Question 5 Comment
Indiana Municipal Power Agency	No	In the previous two version of PRC-004, the data retention time was not six years. How does the SDT plan on making the implementation to the six year data retention when the previous data retention time was 12 months or until your CAP was completed? IMPA believes the previous data retention time requirement should be used on this version of PRC-004.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Exelon	Yes	ComEd: On Measurement M3 & M4 with regards to a dated documentation, do these have to be captured in a system outside of a standard business application for the purpose of locking a tracking date?
Response: Thank you for your comments. **The SDT revised the standard. Measure M1 (old M2) now requires the Transmission Owner, Generation Owner, and Distribution Provider to have documentation of identified and reviewed Protection System operations as well as indicating the ones that were designated as Misoperations. This documentation is needed to ensure compliance with the requirements.**		
Manitoba Hydro	No	Manitoba Hydro suggests that the Evidence Retention period be 3 Calendar Years to align with the data retention required for audits. The standard drafting team has not provided justification for extending the Evidence Retention period to 6 Calendar Years and given that Misoperations will be reported quarterly, it is not clear why 6 Calendar Years of evidence would be required.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		

Organization	Yes or No	Question 5 Comment
Tacoma Power	No	The distinction between M6 and M7 is unclear.
Response: Thank you for your comments. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Ameren	No	1. We believe that the Evidence Retention back to the most recent Compliance Audit is sufficient. The Regional Entity has access to all evidence during the Compliance Audit so it need not be retained after that. TO, GO, and DP are reporting Misoperations quarterly to the Regional Entity, so sufficient ongoing monitoring can occur. 2. Many measures require ‘dated written lists’. We presently use an outage tracking database, which includes our correct operations and Misoperations. Are you requiring us to revise this software so that it automatically tracks date and time of entry of each pertinent item of this standard? Please provide some guidance or point us to what NERC accepts as an equivalent to a ‘dated written list’. 3. In M, please remove ‘each’ as this in an extra word. There seems to be a few other grammatical errors in this sentence.
Response: Thank you for your comments. **1. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.** **2. The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.** **3. The SDT revised the standard.**		
Utility Services, Inc.		
American Electric Power	No	Within M4 and M5, it is not clear what the meaning or intent is of “dated written declaration”, or what it would constitute.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
American Transmission Company, LLC	No	ATC is concerned that the measures defined in M2, M3 and M5 leave out the possibility of using a database to capture the data. Please replace the term "dated written" in the measures section with "dated records". This change allows for records stored in databases, generated from manufacturer programs as well as for written records.
Response: Thank you for your comment. **The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
CenterPoint Energy		
BGE	No	M2. Through M5 requires "written lists, written investigation reports, written declarations, and written action plans...." The intent here should simply be all protection system operations, with auditable investigations reports, and clearly documented action plans. In a modern world these can be accomplished in many ways... The use of the term "written" is archaic....
Response: Thank you for your comment. **The SDT revised the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
Consumers Energy		
ITC	No	Within M2 "Protection System operations" should not be included. Suggest changing this to "BES outages".
Response: Thank you for your comment. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission**		

Organization	Yes or No	Question 5 Comment
Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements. The term BES is not used in the individual requirements and measures because the standard's Applicability Section 4.2.1 states "Protection Systems for Facilities that are part of the BES."		
Wisconsin Electric	No	1. In M1 through M5, the adjective "written" list, report, etc should be removed since any such evidence may be electronic and not necessarily written on paper. 2. In M5, replace "work timetable" with "schedule". 3. M6 should be replaced by a simpler statement like, "The responsible entity shall have dated evidence, such as work management records or other evidence, to demonstrate completion of all plans required by R1.5." M7 is superfluous to M6 and should be removed.
Response: Thank you for your comments. **1. The SDT revised the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.** **2. The SDT used the term "timetable" to remain consistent with the definition of Correction Action Plan (CAP) in the NERC glossary.** **3. The SDT revised the standard. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Duke Energy	No	o M5 - delete this Measure associated with R1.4 consistent with our response to question #3 above. o M6 and M7 should be combined.
Response: Thank you for your comments. **The SDT revised the standard. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan.**		
Constellation Power Generation/Constellation		

Organization	Yes or No	Question 5 Comment
Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

6. **The team has included the "Quarterly Misoperations Reporting Data" table and template, and the supporting reference document. Do you have any specific suggestions for improvement?**

Summary Consideration:

The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".

Several commenters had concerns with the reporting form requiring TADS event ID's. The drafting team responded that correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809.

Several commenters pointed out inconsistencies between the new definition of Misoperation and the categories on the template and Attachment 1. The drafting team responded that the template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group and will match the language approved for use in the revised standard PRC-004.

Several commenters had concerns with the number of cause codes on the template and Attachment 1. The drafting team responded that the NERC SPCS recommended six Cause Codes in the whitepaper "SPCS Input on Uniform Misoperations Reporting" (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. In addition to these six codes, the Misoperation Reporting Template will include "Other/Explainable" and "Unknown/Unexplained".

Several commenters had concerns with clarifying how to handle reporting if no Misoperations have occurred. The drafting team responded that today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.

One commenter had a concern with quarterly reporting requirements versus semi-annual. The drafting team responded that while some regions require semi-annual reporting today, on October 22, 2010 NERC's ERO Executive Management group endorsed an ERO-

RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>Northeast Power Coordinating Council</td><td></td><td></td></tr>
<tr><td>Public Service Enterprise Group Company</td><td>Yes</td><td>1. See the previous comment in response to question 3 regarding semi-annual rather than quarterly reports.
2. In addition, the current format of the Excel file can be improved to make it more "user-friendly." We recommend that the information in Row 3 be converted into Excel “comments” and placed in Row 2. This will eliminate a row from viewing and allow the user to scroll down and still have the valuable information from Row 3 available in Row 2 if needed. In addition, adjusting the font size may allow for more columns to be viewed on one screen.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. While some regions require semi-annual reporting today, on October 22, 2010 NERC’s ERO Executive Management group endorsed an ERO-RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.
2. The template (form) itself will not be a part of this standard.</td></tr>
<tr><td>Hydro One</td><td>No</td><td></td></tr>
<tr><td>Tri-State Generation and Transmission Ass'n - System Protection</td><td>Yes</td><td>All columns that reference “TADS” should be removed. Protection engineers, who will be filing these reports, do not generally have access to the TADS information or filings. Much of the TADS information is not required quarterly so it may not even be available for submittal by the Protection staff. The Regional Entities can supply the TADS information after it is received by them.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, the TADS Reportable Outage = No and TADS Event ID(s) = N/A.		
FirstEnergy	Yes	We ask that it be clear within the standard (maybe a link in the standard) of where you can obtain this form used for quarterly updates.
Response: Thank you for your comment. **The template (form) itself will not be a part of this standard. Guidance for submitting the data will be provided by the Regional Entities or NERC.**		
Pepco Holdings Inc Affiliates	No	
Southern Company Generation	Yes	Eliminate the TADS columns Q, R, and S for generators as this code is meaningless for those entities.
Response: Thank you for your comment. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	Yes	1. Attaching the TADS reference to this template could cause a non reporting for instances in which other entities actually report the TADS information and not the Misoperation. 2. There needs to be consistency with the excel sheet language and the standard itself. Under the definitions tab in the excel sheet the language isn't consistent with the

Organization	Yes or No	Question 6 Comment
		language in the standard itself.
Response: Thank you for your comments. 1. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** 2. **The template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group.**		
MRO's NERC Standards Review Forum	Yes	This should be a requirement.
Response: Thank you for your comment. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Electric Market Policy	Yes	The following comments are related to the "Quarterly Misoperations Reporting Data" table and template: 1) The fields associated with TADS reporting appear to be outside the scope of this reliability standard as stated in the Purpose, therefore we do not agree with inclusion of TADS. 2) The form does not address "action plans" that would be developed in response to Requirement R1, Part 1.4.The form appears to be collecting additional information that goes beyond the Purpose of the standard, i.e., "Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems." Specific information includes: Equipment Type; Facility Voltage (kV); Equipment Removed from Service; Relay Technology.

Organization	Yes or No	Question 6 Comment
		The following comments are related to the reference document, SPCS Input on Uniform Misoperations Reporting: 1) The document and template appear to be focused on collecting data for the purpose of reliability metric ALR4-1. This additional data collection is outside the scope of draft standard PRC-004-3 and the proposed requirements stated in the associated Standards Authorization Request (SAR). Therefore, Dominion recommends that only data necessary to address the standard requirements be collected. 2) Section 3 Misoperation Categories 1st Paragraph and Table 1 Misoperations Categories are not consistent with the categories contained in PRC-004-3. Suggest revising document to include the five categories contained in the draft standard. 3) Section 4 Cause Codes 1st paragrah suggests there are six cause codes in Table 2 which is inconsistent with Table 2 that shows seven cause codes. Suggest revising document in the 1st paragraph to say seven cause codes. 4) Template is hard to use because of the number of horizontal columns of data being requested. The number of fields of data being requested seems to be excessive. Any way to reduce the number of fields? 5) Facility Name (Location of Misoperation) field - IS this asking for location that caused the misoperation or the location of the breakers that operated? For example, when a failed carrier set at Station A causes the other terminal at station B to misoperate during a fault, do I enter Station A or Station B? 6) Equipment Type field - includes Dynamic VAR Systems but does not include Static VAR Systems (SVC for example). Should SVC be included? 7) Facility Voltage (kV) field - includes a choice of <100. Since the BES is defined as those elements >100 KV, this choice should be deleted. 8) For a unit connected generating unit with a 230 kV - 13.8 KV GSU and the 230KV generator output breakers trip when the unit trips, what KV do I enter? For a generator that has a 13.8 KV output breaker and a 230 kV - 13.8 kV GSU and the 13.8 KV breaker trips when the unit trips, what KV do I enter? 9) Equipment Removed from Service field - Isn't this the same information as the Equipment Name field? In the example provided there is no difference in what was entered. The Field Value info apparently limits this to Circuits, Transformers, Buses (and also breakers if the

Organization	Yes or No	Question 6 Comment
		breaker is the only element to trip). Does "Circuits" mean the same as Lines? Suggest Circuits be changed to Lines. Do we include generators? Note that TADS does not require reporting of breaker trips unless a Line or Transformer is affected, shouldn't Misoperations do the same? Note that TADS does not include reporting of Buses or many of the other Equipment Types mentioned in the Misoperations template. Do you want all Equipment Types listed or only Lines and Transformers? We suggest it be limited to one entry focusing on the Equipment (ie Element) that misoperated. 10) Event Description field - The title using the word Event seems to entail the overall event which could include correct operations and Misoperations, and the description indicates a brief description of the event and a detailed misoperation description. But the example data seems to indicate only a misoperation description. Can you include as an example description that has a problem on one line and another line over trips. 11) Causes(s) of Misoperation field - Field is named Cause but description asks for root cause(s). Are you looking for one or are you asking for more than one to be entered? Suggest that the word "root" be removed from description. TADS and other industry benchmarking use Cause not root cause. Suggest that only one choice be allowed for entry. 12) Protection Systems/Components that Misoperate field - Is this redundant since you have asked for a detailed description of the Misoperation in the Event Description field? 13) Relay Technology field - suggest that only one choice be allowed. What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank. 14) Actual CAP Completion Date field - Change name to CAP Actual Completion Date be consistent with the CAP Target Completion Date field. 15) If the SDT ultimately decides to use one or more of the availability reporting systems (TADS or GADS or DADS), we have the following questions/comments: a. Cause Code field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank. b. Event ID(s) field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank.
Response: Thank you for your comments. **In regards to comments related to the Misoperation Reporting Template:** **1) Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by**		

Organization	Yes or No	Question 6 Comment
NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A. 2) Thanks for this comment on how to report action plans when cause is not identified. The drafting team made modifications to the reference document "Quarterly Misoperations Reporting Data. In regards to comments related to the reference document "SPCS Input on Uniform Misoperations Reporting" 1) The SAR identified misoperation data currently collected is not usable to establish a consistent metric for measuring Protection System performance and to establish a standard with uniform applicability and clarifying reporting requirements. 2-3) The SDT cannot revise the SPCS whitepaper. 4-15) These comments are directed at revising and clarifying the Misoperation Reporting Template. The drafting team appreciates all these comments and will refer them to the SPCS and the ERO RAPA group for their use.		
Pacific Northwest Small Public Power Utility Comment Group	Yes	The misoperation category dropdown list does not match the five categories of the definition.
Response: Thank you for your comment and pointing out this inconsistency. The template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group.		
LG&E and KU Energy	Yes	This seems to be the Excel Spreadsheet that NERC has already placed in force effective with 2Q 2011 reporting of Misoperations
Response: Thank you for your comment. The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting."		

Organization	Yes or No	Question 6 Comment
APM Members		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1.
Response: Thank you for your comment.		
Bonneville Power Administration	Yes	1. If NERC really needs the information in the this table, then BPA will support it. However, the way that TADS event IDs are assigned, doesn't easily align with relay misoperations and may be cumbersome and BPA questions whether or not it is be necessary to provide the TADS event ID. 2. BPA suggests that the quarterly reporting requirement given under Section 1.4, Additional Compliance Information is misplaced and suggests that it be given as "ONE" of the requirements. BPA feels that the quarterly reporting table should be all the information that is required, and suggests that measures M1 thru M7 should be removed.
Response: Thank you for your comments. 1. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** 2. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		

Organization	Yes or No	Question 6 Comment
Western Area Power Administration	No	
Westar Energy	Yes	Consistency between the Standard requirements and the 'Quarterly Misoperations Reporting Data' table and template must be ensured.
Response: Thank you for your comment and pointing out this inconsistency. **The drafting team will coordinate with the SPCS and the ERO RAPA group to ensure consistency.**		
Georgia Transmission Corporation	Yes	Spreadsheets make terrible flat databases. Is this spreadsheet wiped clean each quarter or do incomplete CAPs carry over to the next quarter? What is the procedure to have a field modified if the normal "pull down" selection is not adequate?
Response: Thank you for your comment. **The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting". Follow-up detail for incomplete CAPS will be included on the next quarterly report with the field "Resubmittal Check" = Yes.**		
PacifiCorp		No comments.
NextEra Energy, Inc.		If a misoperation has multiple events before a root cause can be determined, then there should be one line item with multiple events, not multiple Misoperations.
Response: Thank you for your comment. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. If a relay has misoperated multiple times before a cause can be determined, the Misoperation Reporting Form will require multiple entries as there will be multiple TADS outages. In this case each line may have the same Operation Category Code, Cause Code, and CAP, etc.**		
Southern Company		

Organization	Yes or No	Question 6 Comment
Flathead Electric Cooperative, Inc.	Yes	Need to make it clear that if there are no Misoperations no report is required.
Response: Thank you for your comment. **Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.**		
Green Country Energy	No	
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP		There needs to be a tight correlation with the Misoperation categories and cause codes introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place. Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up - with unique data requirements and reporting templates.
Response: Thank you for your comment. **The NERC SPCS recommended six Cause Codes in the whitepaper "SPCS Input on Uniform Misoperations Reporting" (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. In addition to these six codes, the Misoperation Reporting Template will include "Unknown/Unexplained" for cases where causes were not identified and properly documented.**		
Oncor Electric Delivery	No	
Private Citizen		

Organization	Yes or No	Question 6 Comment
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
PSE	Yes	We have created an MS Access database to track all misoperation information starting in 2011. An export file is created in the format of the WECC spreadsheet to meet your requirements. We feel that the MS Access database offers several advantages in terms of the ability to sort records in many ways, offering a historical view of Misoperations that will span multiple quarters and years, and still offers all of the “pull down” choices related to definitions and codes.
Response: Thank you for your comment. **Today each Region has its own reporting procedures. The process of how this will be handled in the future is outside the scope of this drafting team.**		
TransAlta		
Entergy Services	Yes	1. The present template does not contain enough cause options. Additional granularity is needed to identify misoperation trends and to provide better focus on potential areas of improvement. For example, selecting AC failure as a misoperation cause which was due to rodent damage, or a relay failure cause due to a leaky roof, doesn’t provide cause information which would be useful to determine whether we are experiencing actual equipment problems or some other unrelated problem. 2. Also, add a “No Problem Found” cause, to address those rare evolving type scenarios which would challenge even the best relay(s) and schemes, and where we actually know what happened, but there is no reasonable corrective action to prevent it from reoccurring.
Response: Thank you for your comment. **1. The NERC SPCS recommended six Cause Codes in the whitepaper “SPCS Input on Uniform Misoperations Reporting” (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail**		

Organization	Yes or No	Question 6 Comment
for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. 2. The SDT is recommending the addition of another Cause Code "Other/Explainable" – for events that are explainable but do not fit into the existing Cause Codes. This would require explanation of the cause in the Event Description field, and if no CAP is proposed, an explanation of why it is not required. These types of Misoperations could be the result of multiple contingency events.		
GenOn Energy		
Indiana Municipal Power Agency	Yes	1. IMPA does not agree with the proposed definition of "Misoperation" and feels that the selections under Misoperation Category are broad and far reaching and will result in the vast majority of operations being termed "Misoperation". 2. In addition the definitions listed in the Definition Tab under the Cause(s) of Misoperation include equipment not covered under other Reliability Standards, such as Telco errors. These Causes need to be reviewed and modified to include only equipment covered by other Reliability Standards.
Response: Thank you for your comment. **1. The SDT disagrees that most operations will be classified as Misoperations. The definition was enhanced to add specificity. The selections under the Misoperation Category in the template will be expanded to accommodate the new definition of Misoperation.** **2. All components of a Protection System are considered in this standard regardless of ownership.**		
Exelon	Yes	Column Q, "Is this a TADs reportable outage", should have NA as an option with a footnote or some acknowledgement that generators do not report or participate in the TADs system. Exelon Nuclear: Column Q should have an "N/A" or and "unknown" field as a selectable option. GO/GOPs do not report or participate in the TADs system.
Response: Thank you for your comment. **If the misoperation involves a generator, the TADS Reportable Outage = No and TADS Event ID(s) = N/A.**		
Manitoba Hydro	Yes	In Column M (Misoperation Category) of the spreadsheet, only 4 Misoperation types are

Organization	Yes or No	Question 6 Comment
		provided for selection - Failure to Trip, Slow Trip, Unnecessary Trip - During Fault, and Unnecessary Trip - Other than Fault. To be consistent with the proposed definition, Failure to Trip should be replaced with Failure to Trip - During Fault, and Failure to Trip - Other than Fault.
Response: Thank you for your comment and pointing out this inconsistency. **The Misoperation Category drop down list in the Misoperation Reporting Template will match the list of Misoperation definitions.**		
Tacoma Power		None
Ameren	Yes	1) For Time Zone use Prevailing Time, e.g. CPT for Central Prevailing Time because that's what EMS systems provide. The switch to Daylight Savings time is simultaneous. 2) Require GO to use their GSU high side voltage for Facility Voltage, rather than the generator voltage which will always be <100 as the Facility Voltage.
Response: Thank you for your comments. **1) Not all utilities EMS switch to Daylight Savings Time, so indicating which Zone the Time is reported is required. Since cities and towns within time zones don't universally switch to daylight savings time, "Prevailing Time" would take on different meanings.** **2) In cases where the generator trips the high side GSU circuit breaker, the Misoperations Reporting Template specifies using the transformer high side voltage for the Facility voltage. In cases where the generator only trips it own unit circuit breaker, it is acceptable to use the generator voltage.**		
Utility Services, Inc.		
American Electric Power	No	
American Transmission Company, LLC	Yes	1. In the supporting document "SPCS Input on Uniform Misoperations Reporting":The Misoperations Categories include Slow trip (i.e., slower than required to meet TPL requirements). The parenthetical should be removed. Using the criteria of being slower than TPL standards, could be used as a loop hole.

Organization	Yes or No	Question 6 Comment
		2. The Cause Code Description for As-left personnel error should be improved by adding a description to make it clear that human error due to ongoing testing is not included. ATC believes the intent is to include only those items when the technician has left the substation in an unwanted state.
Response: Thank you for your comments. **1. In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection to meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported.** **2. The Misoperations Reporting Template has a "Definition" tab with detailed definitions for the Cause Codes. It clarifies the As-left Personnel Error category as things left following maintenance or construction.**		
CenterPoint Energy		
BGE	Yes	The Application Guidelines need to be incorporated into the standard or specifically called out as a binding attachment to the standard.
Response: Thank you for your comment. **The ERO-RAPA group has indicated it plans to incorporate approved changes to the reference document titled "Quarterly Misoperations Reporting Data/Fields" into the Quarterly Misoperations Reporting Template. The reference document will be posted concurrently with the draft standard.**		
Consumers Energy	Yes	The Misoperation Category descriptions in the reporting template should match the wording of the proposed Misoperation definition as closely as possible.
Response: Thank you for your comment and pointing out this inconsistency. **The Misoperation Category drop down list in the Misoperation Reporting Template will match the list of Misoperation definitions.**		
ITC	Yes	Misoperation reports can be quite lengthy to provide the needed details. Because there can be significant information for an adequate report a spreadsheet is not the best way to collect and distribute this data. Higher level software applications should be used.

Organization	Yes or No	Question 6 Comment
Response: Thanks for your comment. **The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting". If additional significant information is required, most Regional Entities provide the opportunity to attach additional documentation when submitting misoperation data. Today each Region has its own reporting procedures to report Misoperations. The process of how this will be handled in the future is outside the scope of this drafting team.**		
Wisconsin Electric		
Duke Energy	Yes	1. TADS transmission data may not be accessible to generators, and generator data may not be reported in TADS. 2. Need to add a 100 kV option on the template (column J).
Response: Thank you for your comments. **1. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** **2. The template has been modified and now includes a 100 kV option.**		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board	Yes	1) Under "Applicability" in PRC-004-3, SUB recommends that the language lists Functional Entities (TO, GO, DP) who own the following Facilities (Protection Systems, SPS). The current version of the PRC-004-3 draft lists Functional Entities and Facilities as separate applicability. 2) SUB would ask for PRC-004-3 to clarify whether or not Functional Entities would be required to submit a quarterly report if they do not have any Misoperations occur during the quarter. SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect

Organization	Yes or No	Question 6 Comment
		penalty funds.
Response: Thank you for your comments. **2. 1. The Applicability should be read as a logical 'and' statement. For example, if you are a Distribution Provider and own Protection Systems that are a part of the BES, then the standard is applicable. If you are a Distribution Provider and do not own Protection Systems that are a part of the BES, then the standard is not applicable.** **3. 2. Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.**		
BC Hydro		

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.

Summary Consideration:

Several comments were received on various possible conflicts, including possible conflicts with other NERC standards, Section 1600 data requests, Section 215 of the Federal Power Act, and NRC regulations. In all of these cases, the drafting team reviewed the issues cited and feels that no conflict exists.

In response to one comment, the drafting team modified the Background statement to better reflect the interaction between this standard and the WECC regional Misoperations reporting standard.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council		
Public Service Enterprise Group Company		
Hydro One	No	
Tri-State Generation and Transmission Ass'n - System Protection	No	None
Response: Thank you for your comment.		
FirstEnergy	No	Not aware of any at this time.
Response: Thank you for your comment.		
Pepco Holdings Inc Affiliates	No	

Organization	Yes or No	Question 7 Comment
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	
MRO's NERC Standards Review Forum	Yes	Where does PRC-009 (new PRC-006) & PRC-020 overlap or are they in conflict with this standard?
Response: Thank you for your comment. **The misoperation of Underfrequency equipment applied on the BES is covered by this standard. There is no conflict with PRC-009-0 and PRC-006-1 as they deal with Underfrequency equipment performance only during a legitimate Underfrequency Load-shedding event. There is no conflict with PRC-020 as it deals with Undervoltage Load-shedding which is specifically excluded from this standard.**		
Electric Market Policy	Yes	Conflict: Collection of additional data pursuant to Section 1600 of NERC's Rules of Procedure, such as TADS information, does not belong in a NERC Reliability Standard.
Response: Thank you for your comment. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Pacific Northwest Small Public Power Utility Comment Group	Yes	Conflict: Section 215 of the Federal Power Act. At least one regional entity is consistently applying PRC-004-1 to distribution systems in violation of the FPA. Version 3 adds nothing to limit or clarify the extent of the standard's reach.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **There is no conflict between Section 215 of the Federal Power Act and this standard. This standard is for "Protection Systems for Facilities that are part of the BES" as stated in the Applicability section.**		
LG&E and KU Energy		
APM Members		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Response: Thank you for your comment.		
Bonneville Power Administration	No	BPA feels that in regards to the final paragraph of Section 5, Background, states that with regard to the WECC regional misoperation standard (PRC-004-WECC-1), complying with the more stringent standard will ensure compliance with the less stringent as well. BPA feels that this is not correct because the two standards have different requirements, and will require different actions to be in compliance with both. BPA believes that it would be helpful if WECC would rescind PRC-004-WECC-1.BPA asks, "Will the regional criterion, such as PRC-003-WECC-CRT-1 be rescinded?"
Response: Thank you for your comment. **The drafting team revised the Background section of the draft standard that discusses the WECC Regional Reliability Standard. PRC-004-WECC-1 and the regional criteria will not be rescinded by this drafting team.**		
Western Area Power Administration		
Westar Energy		

Organization	Yes or No	Question 7 Comment
Georgia Transmission Corporation	No	
PacifiCorp		No comments.
Response: Thank you for your comment.		
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.	Yes	You can't require the quarterly reporting of a non-event. Reporting should only be required if there is an actual BES Misoperation, no null reports.
Response: Thank you for your comment. **Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is yet to be determined.**		
Green Country Energy	No	
Hydro-Quebec TransÃ ‰ nergie	No	
Ingleside Cogeneration LP	No	
Oncor Electric Delivery	No	
Private Citizen	No	
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland		None

Organization	Yes or No	Question 7 Comment
Utilities, Inc.		
Response: Thank you for your comment.		
PSE	No	
TransAlta		
Entergy Services		
GenOn Energy	No	
Indiana Municipal Power Agency		no comment
Response: Thank you for your comment.		
Exelon	No	
Manitoba Hydro	Yes	1. A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the Protection System elements that are included in the BES according to provincial legislation and the NERC definition. This may impact the Protection System Misoperations that are reported. 2. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of PRC-004-3 and the associated Misoperation reporting requirements may differ for Canadian entities and entities under FERC jurisdiction.
Response: Thank you for your comments. **1. The standard is applicable to BES Facilities; therefore, the applicability of the standard depends on the individual jurisdiction's definition of BES.** **2. The standard will become effective according to the applicable regulatory approval and its associated Implementation Plan.**		

Organization	Yes or No	Question 7 Comment
Tacoma Power		None
Ameren		
Utility Services, Inc.		
American Electric Power		AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, however, the definitions and reporting requirements for this standard would potentially be quite different from those required an RTO. This would not only produce duplication of efforts, but would also result in conflicting metrics.
Response: Thank you for your comment. **NERC does not regulate RTO requirements.**		
American Transmission Company, LLC		
CenterPoint Energy		
BGE	No	No comment.
Response: Thank you for your comment.		
Consumers Energy		
ITC		
Wisconsin Electric		
Duke Energy	No	
Constellation Power	Yes	Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR

Organization	Yes or No	Question 7 Comment
Generation/Constellation Energy Nuclear Group		50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Response: Thank you for your comment. **The requirement(s) you cite cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.**		
Springfield Utility Board		
BC Hydro		

8. **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.**

Summary Consideration:

Most commenters argued that the regions – and WECC in particular – should not be allowed to have a regional standard for Misoperations reporting. The SDT responded that any Regional Entity is allowed to have regional standards that have more stringent requirements than the continent-wide standards. See NERC Rules of Procedure, Section 312.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council		
Public Service Enterprise Group Company		
Hydro One		
Tri-State Generation and Transmission Ass'n - System Protection		None.
Response: Thank you for your comment.		
FirstEnergy	Regional Variance:	This standard should be coordinated with regional reporting requirements to avoid duplication of efforts. For instance, RFC has Misoperations reporting requirements (per procedure titled "Reporting, Review, and Analysis of Protection System and Under Voltage Load Shedding (UVLS) Misoperations") for Protection systems AND UVLS system. Since this standard covers reporting of Protection system Misoperations, it should include a variance for the RFC region, or NERC should direct RFC to revise their reporting requirements to remove protection system Misoperations to avoid redundancy.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. These regional reporting requirements will be coordinated with this standard. Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.		
Pepco Holdings Inc Affiliates		
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team		
MRO's NERC Standards Review Forum		
Electric Market Policy	Regional Variance:	Regional Variance: WECC Should consider the fact that WECC has Misoperation requirements that are not recognized by the other regions and the purpose of this standard is to standardize Misoperation documentation, reporting and definition of a Misoperation. Suggest no regional variances be allowed.
Response: Thank you for your comment. Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		

Organization	Yes or No	Question 8 Comment
APM Members		
PPL Generation		
Florida Municipal Power Agency		see comments to Question 1.
Response: Thank you for your comment.		
Bonneville Power Administration		
Western Area Power Administration		
Westar Energy		
Georgia Transmission Corporation		
PacifiCorp		No comments.
Response: Thank you for your comment.		
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.		
Green Country Energy		

Organization	Yes or No	Question 8 Comment
Hydro-Quebec TransÃ ‰ nergie		
Ingleside Cogeneration LP		
Oncor Electric Delivery		
Private Citizen		
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
Response: Thank you for your comment.		
PSE		
TransAlta		
Entergy Services		
GenOn Energy		
Indiana Municipal Power Agency		no comment
Response: Thank you for your comment.		
Exelon		
Manitoba Hydro		

Organization	Yes or No	Question 8 Comment
Tacoma Power		No more stringent regional variance should be applied for WECC.
Response: Thank you for your comment. **Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
Ameren		
Utility Services, Inc.		
American Electric Power		We see no need for regional variances, whether for WECC or any other region.
Response: Thank you for your comment. **Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
American Transmission Company, LLC		
CenterPoint Energy		
BGE		No comment.
Response: Thank you for your comment.		
Consumers Energy		
ITC		
Wisconsin Electric		
Duke Energy		

Organization	Yes or No	Question 8 Comment
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

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

Summary Consideration:

Numerous commenters were concerned about the prescriptive nature of the Guidelines and Technical Basis section of the standard. The SDT clarified that the Guidelines and Technical Basis section of the standard is included to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable.

Some commenters questioned the inclusion of SPS, RAS, UVLS, UFLS, and SPR in the draft standard. The SDT clarified that SPS and RAS Misoperations are excluded from PRC-004-3 because they will be addressed in the second phase of this project by another team. UVLS Misoperations are excluded because they are explicitly covered by PRC-022-1. UFLS Misoperations are included because not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards. SPR Misoperations are not included because they are not currently part of the Protection System definition.

Several commenters were concerned about the implementation time being too short. The drafting team agreed and increased the implementation time for the new standard.

Some commenters questioned the purpose of the Background section. The SDT clarified that the Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.

A few commenters questioned which entity had the responsibility of reporting Misoperations at an interface. The SDT clarified that the owner of the Protection System component that misoperated is required to report the misoperation.

A number of commenters questioned the location of the Misoperations reporting within the compliance section of the standard. The drafting team consulted NERC staff and decided the compliance section is the appropriate place for Misoperations reporting.

A few commenters questioned whether operations occurring during generator synchronization would be covered under PRC-004-3. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these types of operations are excluded because the generating unit is not synchronized and is isolated from the BES.

Organization	Yes or No	Question 9 Comment

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	Yes	Although the inclusion of the Application Guidelines is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive.
Response: Thank you for your comment. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Guidelines and Technical Basis section has been revised and the text referred to has been deleted.**		
Public Service Enterprise Group Company		
Hydro One	Yes	1. Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive. 2. Also, we have concerns with the identified time lines in R1.2, R1.3 and R1.4. Is the intent of the requirement for the RE to initiate action within the specified time once the misoperation is identified? The identification of a misoperation may not occur for some time after the actual protection system operation as there can be a lag between an operation occurring and the analysis of that operation. Some Misoperations may be obvious but some others not so much. We think that more clarity is needed here.
Response: Thank you for your comments. **1. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Guidelines and Technical Basis section has been revised and the text referred to has been deleted.**		

Organization	Yes or No	Question 9 Comment
2. The standard has been revised. The entity has 120 days after the occurrence of the operation to determine whether or not it was a Misoperation. For each designated Misoperation, investigate and document the findings including whether or not a cause is identified.		
Tri-State Generation and Transmission Ass'n - System Protection	Yes	1. As stated earlier, we believe the requirements should be expanded to state what is required rather than putting requirements in the measures. At that point we would be in a better position to address our comments to the requirements. 2. We believe that UVLS and SPS/RAS should be included in this standard and then PRC-012, Requirements R1.6, R1.7, and PRC-016 can be eliminated. If the standard is not changed to include UVLS and SPS, why is UVLS excluded but not UFLS? 3. Corrective Action Plan is defined in the NERC Glossary of Terms. Requirement 1, Part 1.3 should not describe what should be included in the CAP.
Response: Thank you for your comments. **1. The drafting team revised the requirements and measures for clarity.** **2. Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. Presently, not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards.** **3. The drafting team removed the additional details from Corrective Action Plan description.**		
FirstEnergy	Yes	1. R1 Subpart 1.5 - We would appreciate clarification on the following regarding what constitutes successful completion of the Corrective Action Plan: Given the scenario of a maintenance error that caused the operation of a protection system, we understand that per this standard, if this misoperation is reported, and the error was corrected per the reported corrective action plan, then the entity is compliant with the standard even if the human error occurs again on a separately reported misoperation incident. Please confirm this understanding. 2. Applicability Section - The proposed standard excludes SPS, RAS, and UVLS systems. However, we do not see an exclusion for UFLS. The standard should clarify whether or not UFLS are applicable. 3. Effective Date - We believe that the proposed 3 month implementation of PRC-004-3 is

Organization	Yes or No	Question 9 Comment
		much too short for an entity to be able to achieve auditable compliance because it may require changes to internal procedures and business unit awareness of the new standard. We suggest at least 6 months after regulatory approval.
Response: Thank you for your comments. 1. **The definition of a Misoperation has been modified to exclude an operation related to on-site maintenance, testing, construction or commissioning activities. If an operation occurred after the on-site activity and was related to a maintenance error, then it would be a Misoperation. The entity develops a CAP with the intention of correcting the cause of the Misoperation. The entity is responsible for its system performance and it is to its benefit to quickly correct Misoperations and prevent future Misoperations of a similar nature. The CAP is complete once all of the identified actions have been performed. The recurrence of a similar Misoperation at the same location is not a PRC-004-3 violation; however, it is an indication of the ineffectiveness of the completed CAP. A new CAP will need to be developed to remedy the specific problem. The new CAP should consider why the previous CAP did not result in the avoidance of a future Misoperation.** 2. **Presently, not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards.** 3. **The drafting team agreed and increased the implementation time for the new standard.**		
Pepco Holdings Inc Affiliates	Yes	1. Section 4.2.2 should be revised to read "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Voltage and Under Frequency load shedding programs, and Sudden Pressure Relays (SPR) are excluded from this standard." There has been past confusion as to whether the misoperation of an Underfrequency relay, which is part of a regional load shedding program, is reportable under this standard. Excluding UFLS programs eliminates this confusion. Adding SPR to the exclusions will also eliminate confusion. 2. Also, as mentioned in Question #1 the qualifying comments in the "Application Guidelines" section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a misoperation and what does not. 3. However, the remaining sections of the "Application Guidelines" appear to be either tutorial, or background, in nature and should not be part of the standard itself. 4. Compliance data submittal C1.4 requires a quarterly report (ERO spreadsheet) be

Organization	Yes or No	Question 9 Comment
		submitted within 60 calendar days following the end of each calendar quarter. However, as was pointed out repeatedly, due to the difficulty in obtaining outages it is highly unlikely that many misoperation investigations could be completed, or corrective action plans developed / implemented, within 60 days after a quarter ends (particularly for those events which occur late in the quarter). For instance, suppose a misoperation occurs in June (second quarter). Data submittal will be required 60 days after the quarter ends (August 31). However, outages to conduct the necessary diagnostic testing will not be available until mid to late September. Therefore in an attempt to improve the percentage of reported events where investigations are complete and causes determined, we would suggest requiring the data submittal 90 days following the end of each quarter. This additional delay in data submittal will not impact the reliability of the BES, since any protective system misoperation contributing to a major system disturbance is already being thoroughly reviewed / investigated under EOP-004 Disturbance Reporting Requirements. 5. Under Section C 1.4 Additional Compliance Information, there is a reporting requirement. This should be included as a specific requirement in Section B. If not included in Sec B, it could easily be missed by the applicable entity as a requirement.

Response: Thank you for your comments.

1. **UFLS Misoperations on the BES are not excluded from this standard because they are not covered by any existing NERC standards. The standard relies on the applicable FERC approved definition of Protection Systems which currently does not include Sudden Pressure Relays (SPRs).**
2. **The drafting team revised the definition of Misoperation in the draft standard.**
3. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems.**
4. **The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the results. The standard was further modified to allow a time period of 60 days to develop either; the corrective action plan when a cause was determined; or, an action plan of additional steps if the investigation failed to determine a cause. The requirement for data submission has been eliminated. The data submission time frame has been adjusted to 2 calendar months after the quarter.**

Organization	Yes or No	Question 9 Comment
5. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Southern Company Generation	**Yes**	1) In 4.2.2, point to PRC-016 for SPS Misoperations. 2) In suggesting to use the objectives listed (on page 5 of the 09 Jun 2011 draft standard) as the recommended requirements in the comments to Question 2 above, the removal of "faults" from the first objective was intentional. Generator Owners are not advised of "all faults" and have no way of knowing of all faults. Our experience has been that some Protection System will ultimately operate whenever a Protection System Misoperation occurs, therefore the suggested R1 was written excluding "all faults". 3) Another reason for eliminating all of the time frames suggested by R1 (R1.2, R1.3, and R1.4) relates to the 60 day reporting requirement to regions. A misoperation can occur on the last day of the quarter which must be reported 60 days later. The R1 subsections above time frames overlap the 60 days for a misoperation occurring late in the quarter. The simplified requirements suggested eliminate this problem. 4) We disagree with the statement made in item 3 of the Guidelines and Technical Basis section (page 12) of the draft standard. If the system did not perform as it was intended to (designed to), then it is a misoperation. 5) It is unclear what the phrase "situations that challenge a Protection System" means on page 13, Part 1.1 of the draft standard. 6) The exhaustive description of an investigation (page 13 Part 1.2 paragraph) should only be required where a definitive cause is not identified. For those cases where the cause has been determined, only the bottom line needs to be formally documented. 7) Will the Guidelines and Technical Basis section of the draft standard (p 12-16) become part of the standard? It is not referenced in Section F Associated Documents (p 11). 8) Will the Background section (A5) be retained with the standard?

Organization	Yes or No	Question 9 Comment
		9) Are revisions to Corrective Action Plans allowed to facilitate handling contingencies?

Response: Thank you for your comments.

1. **It is not a good practice to reference other Reliability Standards within a standard because of the dynamic nature of standards development.**
2. **The drafting team revised the standard and 'Faults' have been removed as an initiating event. A Protection System operation of an interrupting device is now the initiating event for an investigation.**
3. **The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the results. The standard was further modified to allow a time period of 60 days to develop either; the Corrective Action Plan when a cause was determined; or, an action plan of additional steps if the investigation failed to determine a cause. The drafting team has retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
4. **In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection to meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported.**
5. **The drafting team revised the draft standard and has modified the Guidelines and Technical Basis section as well to reflect the new requirements.**
6. **The drafting team revised the draft standard and has modified the Guidelines and Technical Basis section as well to reflect the new requirements.**
7. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.**
8. **Yes.**
9. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**

Organization	Yes or No	Question 9 Comment
Transmission Access Policy Study Group	Yes	We understand that the draft standard was drafted by a "rapid development team" rather than by a stakeholder Standard Drafting Team. This new rapid development team process should not displace or compromise the stakeholder process. TAPS supports the goal of developing better standards more efficiently. If NERC and Regional staff draft a standard

Organization	Yes or No	Question 9 Comment
		without the benefit of significant industry input, however, we could risk moving toward greater inefficiency and delay, because problems that could have been addressed informally in drafting will instead have to be addressed formally through comments and revisions. Instead, the rapid development team should develop only the SAR, with the drafting of the standard left to the Standard Drafting Team, advised by technical writers and attorneys as appropriate.
Response: Thank you for your comment.		
SPP Reliability Standards Development Team		1. Would like clarification on failures during the synchronization of a unit. Clear line to when the point of misoperation could occur. 2. Shouldn't under frequency load shed also be excluded to be addressed at a later date? 3. Under the applicability section shouldn't the wording have been kept from the last posting that it would be distribution provider that owns a BES protection system? 4. Under compliance section third line protection needs to be capitalized. 5. On the same line shall submit a quarterly report. Need to insert, "quarterly report for the previous quarter".
Response: Thank you for your comments. **1. The drafting team revised the draft standard, and the Guidelines and Technical Basis section of the standard includes an explanation regarding the synchronization of a unit.** **2. UFLS Misoperations are included because they are not covered by existing NERC standards.** **3. The Applicability should be read as a logical 'and' statement. For example, if you are a Distribution Provider and own Protection Systems that are a part of the BES, then the standard is applicable. If you are a Distribution Provider and do not own Protection Systems that are a part of the BES, then the standard is not applicable.** **4. Thank you for pointing this out.** **5. Thank you for your comment**		
MRO's NERC Standards Review Forum	Yes	1. Clearly exclude power plant trips when they aren't part of the BES as Misoperations. Trips can occur easily during synchronization and may not be a reliability problem. There are many mechanical issues related to a power plant that may result in an

Organization	Yes or No	Question 9 Comment
		electrical synchronization trip. It's best to avoid inadvertently requiring unnecessary work that won't benefit reliability by clearly excluding plants that are not connected to the BES or plants in the process of synchronizing to the BES. 2. Non-BES plants should all be excluded.
Response: Thank you for your comment. **1. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these types of operations are excluded because the generating unit is not synchronized and is isolated from the BES.** **2. Non-BES connected plants are excluded from applicability to this standard due to the NERC Statement of Compliance Registry Criteria, Section III(c).**		
Electric Market Policy	Yes	Dominion offers the following comments: 1) The "Rationale for R1" suggest that this revision will afford "enhanced reporting and the development of performance metrics that indicate overall system health, as well as facilitate the sharing of 'lessons learned'." Dominion notes that both performance metrics and lessons learned are outside of the scope of this reliability standard. Additionally, NERC is developing an Event Analysis process (currently in field trial) that includes a lessons learned component. Suggest NERC review the current process of blending data collection for other purposes with compliance. 2) The "Guidelines and Technical Basis" section appears to contain language that one could interpret as expanding the Requirements. Suggest clearly noting that this section is guidance only and not intended for compliance. 3) Section (5. Background) should be removed from the standard. This has no relevance to the Requirements or Measures of the new standard. 4)PRC 003 had the Regional Entity as a Functional Entity under Applicability; previous versions of PRC 004 have the TO, GO and DP listed as the Functional Entities under Applicability. PRC004-3 Background states that "PRC 003-1 is not enforceable…" and "This represents a potential reliability gap". According to PRC 004-3, responsible entities are to report to the Regional entities quarterly, so why isn't the Regional Entity listed in the new standard as a Functional Entity? Is the objective to require the regions to submit the data collected to NERC?

Organization	Yes or No	Question 9 Comment
		5)(R1.5) does not allow for extending the CAP beyond the pre-determined timeline when system conditions will not allow for equipment removal, outages, or project schedule changes. There are circumstances where outages continue to move and schedules are adjusted due to operating conditions or limitations that are beyond the control of those developing a projected CAP work timetable. Timetables can be set but it is not unusual that later, when the work is to be performed, that system conditions dictate a change in the schedule. 6) In (C.1.4) the Regional Entity and ERO references require more emphasis by creating a separate section listing Regional Entity requirements. 7) In the Application Guidelines; the Misoperation Definitions (1 -5), could include better examples or "bulleted" examples. 8) Consider not switching to landscape in the middle of the document. If landscape must be used move Regional Variances, Interpretations, and Associated Documentation to a new page. 9) Need to revise "Guidelines and Technical Basis" section to include Slow trip - other than Fault

Response: Thank you for your comments.

1. **The drafting team retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
2. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable**
3. **The Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.**
4. **The Regional Entities can no longer be applicable functional entities in a Reliability Standard. The drafting team retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
5. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**
6. **The language in C 1.4 has been revised to refer to the Compliance Enforcement Authority.**
7. **The drafting team revised the definition of Misoperation as well as the Application Guidelines that discusses the new**

Organization	Yes or No	Question 9 Comment
definition. 8. Thank you for your comment. 9. The drafting team revised the definition of Misoperation as well as the Guidelines and Technical Basis section that discusses the new definition.		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members		
PPL Generation		Requirement 1.5 states that the procedure shall include, "A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented." Schedule changes may be needed as a result of unforeseen events. This should be clarified to be “A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable or document the basis for needed schedule changes. The procedure shall also include a requirement to document its completion as implemented.”
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
Florida Municipal Power Agency		see comments to Question 1
Bonneville Power Administration		BPA believes that the requirements in this standard to create and provide procedures and detailed descriptions of the processes used to analyze relay Misoperations are burdensome. In addition, BPA feels that the requirement to provide your own processes and procedures results in extra steps that waste valuable time. Documenting these processes and procedures and then providing them in self-certifications and at audits results in appreciable work. This step also results in one more potential audit violation.

Organization	Yes or No	Question 9 Comment
		This approach is the one that was used in PRC-005-1. There it resulted in inconsistent levels of relay maintenance between entities and inequitable penalties. That approach is being dropped in PRC-005-2, and BPA believes that it should not be used in this standard either. A more concise and acceptable standard would simply specify the minimum requirements for analyzing and documenting relay operations and not require the documentation of procedures and detailed descriptions of the processes used by individual entities.
Response: Thank you for your comment. **The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**		
Western Area Power Administration	Yes	The SAR refers to WECC standards PRC-003-STD-1 and PRC-004-WECC-1. It talks about how those standards might overlap. It is our understanding that PRC-004-WECC-1 replaces PRC-003-STD-1 so we don't understand what NERC is getting at. Only one of those standards should be active at any point in time.
Response: Thank you for your comment. **The SAR is not referring to the two WECC standards overlapping each other, rather it is referring to those standards overlapping the proposed NERC Reliability Standard PRC-004-3.**		
Westar Energy		
Georgia Transmission Corporation	Yes	Will TADS be able to show the percentages of Misoperations versus total number of operations?
Response: Thank you for your comment. **This question is beyond the scope of this drafting team.**		
PacifiCorp		PacifiCorp suggests that Section 4.2.2 (regarding applicability of facilities) be revised to state as follows: "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs, and Under Voltage Load Shedding programs are excluded from this standard." PacifiCorp believes that the same rationale for excluding

Organization	Yes or No	Question 9 Comment
		UVLS programs from this proposed standard should apply for UFLS programs. If the Standards Drafting Team has a specific rationale for making UFLS programs subject to this standard, please provide an explanation as part of the revised standard circulated for the next formal comment and voting period. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
Response: Thank you for your comment. **Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by existing NERC standards.**		
NextEra Energy, Inc.	Yes	The CAPs and action plans are living documents that should be revised as additional information is gained. Requirement 1.3 should be revised to read (highlighted section added): o A Corrective Action Plan (CAP) (which may be amended as appropriate) that includes: Requirement 1.4 should be revised to read (highlighted section added): o An action plan (which may be amended as appropriate) that identifies:
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
Southern Company	Yes	Although we feel that tie back to TADS reporting will not accomplish the needed data unless TADS is modified to include 100-kV and above and generation facilities. Unless this is done, The tie back to TADS should be eliminated, if implemented, we would suggest the following modification: The recommendation is to state the actual range of TADS data collected. Proposed text - A review of the Transmission Availability Data System (TADS) data (20XX to 20XX) reveals that the fourth ranked initiating cause of BES outages not related to weather is “Failed Protection System Equipment.”
Response: Thank you for your comment. **Changes to TADS are beyond the scope of this drafting team.**		

Organization	Yes or No	Question 9 Comment
Flathead Electric Cooperative, Inc.		
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie	No	
Ingleside Cogeneration LP		
Oncor Electric Delivery	No	
Private Citizen	Yes	I thank the drafting team for their efforts to date and for the opportunity to comment. The job of a drafting team is not easy. My comments are as follows: 1) I just wanted to add what I thought the true Purpose of the standard is/should be: Misoperation analysis is a reactive tool - one waits for a Misoperation, then analyzes why it happened with the purpose of determining what, if any, changes need to be made to prevent another occurrence in the entity's system. Changes could be simple or complex, at one location or at many locations. Primarily, you are working to prevent a SECOND Misoperation. The SECOND misoperation could be either on existing system(s) or on future systems. I think it is important to note that it is the occurrence of the SECOND misoperation that is the true indicator of whether the efforts to prevent a Misoperation have been successful. A SECOND Misoperation indicates that it has not. 2) In R1, the drafting team calls for each entity to have a procedure. I am unclear on what benefit this provides, other than giving the auditors something to audit. Why not just call for an entity to do XYZ rather than say they must have a procedure that says they will do XYZ and they must follow the procedure. I see requiring a procedure as unnecessary documentation. Can the drafting team comment on why they asked for a procedure? 3) In R1.1, the drafting team calls for a "detailed" description. There is no measure for 'detailed". I believe the drafting team should seek to avoid such undefined terms. Shouldn't the standard just call for a procedure that includes the things listed in the

Organization	Yes or No	Question 9 Comment
		standard? Or better yet, not call for a procedure at all, but just say you must do XYZ? 4) In the Background, it states that one goal of the standard is to collect data to establish a metric to measure Protection System performance. While I think this is a worthy goal in theory, I am skeptical about its usefulness in practice. Protection systems are an Art, not a science, and while most protection systems are made from the same building blocks, the application of them can vary wildly from utility to utility. Before requiring data collection - which would presumably cause a utility to get a NERC violation for failing to send in the data - I would be curious to know how this has worked in the regions that do, today, collect this data. For instance, I believe SERC collects this kind of data. Has this proven useful for developing a metric for SERC entities? If it has not, why not? Let's not repeat a mistake on a continent wide basis. 5) CAPs - the drafting team has written all kinds of rules for CAPs, including trying to hold the entity to a work timetable. What if the entity chooses to say it will take 100 years to fix so that they avoid the possibility of getting a violation for missing their timetable? I personally think CAPs should be eliminated from the standard as they are simply un-workable. You cannot know whether the CAP makes sense without evaluating them on a case-by-case basis. Consider that the CAP actions fall into three broad areas: a) Do nothing (for any of a boat-load of reasons) b) Correct the issue at this one location c) Correct the issue at all locations Generally, c) is preferred, but there may be times when a) is the best solution, because fixing the issue may make things worse. So, instead, how about a performance standard, whereby an entity gets a violation if a Misoperation occurs a SECOND time. I'll be the first to admit that the devil is in the details, but at least in this case, we're getting at the true reason for the standard - preventing that SECOND occurrence. Ultimately, we don't care how they do it, as long as they do it.

Response: Thank you for your comments.

1. **Thank you for your comment.**
2. **Having a standardized process provides a consistent application for evaluating Protection System operations. The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**

Organization	Yes or No	Question 9 Comment
3. The drafting team revised the standard and removed the word 'detailed'. **4. Consistently reported Misoperation data can be used to measure the reliability of BES Protection Systems over time.** **5. The SDT appreciates your observations. The SDT believes the establishment and completion of CAPs for Misoperations will be more effective in reducing future Misoperations than imposing violations for repeated Misoperations.**		
Consolidated Edison Co. of NY, Inc.	Yes	Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive.
Response: Thank you for your comment. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. They are not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems.**		
Orange and Rockland Utilities, Inc.		None
PSE		
TransAlta		
Entergy Services		There are instances when an entity will justifiably need to defer a corrective action plan. The standard needs to include provisions to be able to adjust or defer corrective action plans if necessary.
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
GenOn Energy	Yes	The attempt to keep the Standard simple and straightforward is appreciated. 1. In the Requirements section, please simply state the intended requirement and

Organization	Yes or No	Question 9 Comment
		eliminate the repeated use of catch-all terms such as "any" and "all" which open the door to future unintended interpretations. 2. In R1.1, a "detailed" description is arbitrary and subjective. Reword the statement as follows: "A description of the processes used to:" 3. In R1.1.1, reword the requirement, "Identify and document Faults and Protection System operations." Documenting "all BES Faults" covers the entire continent. 4. In Section R1.3 and R1.4, it is suggested to replace "a work timetable" with "a projected schedule."
Response: Thank you for your comment **1. The SDT revised the draft standard.** **2. The SDT revised the draft standard and the word 'detailed' has been removed.** **3. The requirements have been rewritten. The "BES" reference was removed because BES is specified in the Applicability section 4.2.1. The "Faults" reference was removed because Misoperations may occur during non-fault conditions.** **4. The drafting team used the word 'timetable' to be consistent with the definition of a 'Corrective Action Plan' in the NERC Glossary of Terms.**		
Indiana Municipal Power Agency	Yes	1. A NERC Rapid Development Team (one industry stakeholder out of ten individuals) drafted the SAR and the first draft copy of PRC-004-3. IMPA believes SAR development in this manner is fine, but the first draft of a standard should not be written by the NERC Rapid Development Team. This new process should not compromise the current stakeholder process of writing reliability standards. By using the Rapid Development Team in the attempt to gain efficiency or speed, the risk of becoming inefficient and increasing drafting standard time is greater because problems will have to be address formally through comments and revisions instead of through the informal drafting work of the stakeholder's standard drafting team. 2. IMPA appreciates the effort of trying to make the standard easier to understand by the use of Application Guidelines, but we are concern that the Application Guidelines will become, by association, part of the requirements of the standard. Application Guidelines will be used by auditors as a draft of what a Compliance Program should include and that registered entities will be required to comply with the suggestions

Organization	Yes or No	Question 9 Comment
		listed for Part 1.1 - Part 1.4 and Section C-1.4. For instance, it is stated that an investigation report generally includes the following information: 1) initial evidence, 2) probable or potential causes, 3) tests and studies, and 4) conclusions. Are utilities going to be required to have the supporting documentation required for each of these steps? For instance, as stated in the Application Guideline, initial evidence "...contains the sequence of events, relay targets, and a summary of Disturbance Monitoring Equipment (DME) records." However not all registered entities to which this draft Standard would apply to are currently required to have sequence of events and/or DME's. If this source of information is not available to them will they be penalized or forced to install this equipment thereby subjecting them to further Standards? In addition short circuit and coordination studies are mentioned as being included in report. These studies can be costly and time consuming - will utilities be required to provide these in a report for each operation in order to prove that it was not a "Misoperation"? Guidelines should be viewed as just that - a guideline and should not be viewed as what a utility should include in their Compliance Program. For this standard, it has about a page and a quarter of requirements and almost five pages of Application Guidelines to tell an entity how to be in compliant. The requirements should be written in a manner to stand by themselves without guidelines and allow an entity the option of determining the best method of being in compliance with the requirement.
Response: Thank you for your comments. **1. The drafting team forwarded your comment to the NERC Standards Committee and NERC staff.** **2. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable.**		
Exelon	Yes	What are the reporting expectations when a Protection System misoperation occurs between entities and the failure is with the one of the entities? Would the entity not responsible for the cause also report a misoperation as a means to show cooperation?
Response: Thank you for your comments. **The owner of the Protection System component that misoperated is required to report the misoperation.**		

Organization	Yes or No	Question 9 Comment
Manitoba Hydro		
Tacoma Power		The word 'detailed' should be removed from R1.1. Under R1.3, replace 'Interim corrective actions' with 'Interim corrective or mitigating actions.'
Response: Thank you for your comment. **The SDT revised the draft standard and the word 'detailed' has been removed.**		
Ameren		1) The industry is in the process of adopting the RAPA template. We disagree with the Background statement that Misoperation data, as currently collected and reported is not usable. It seems to us that plenty of Misoperation statistics have been issued, though they may be misleading. 2) We have been through multiple audits and regional reviews of our reported Misoperations, and strongly disagree with the Background statement that the present PRC003 / 4 status is a 'reliability gap'. 3) Are the "Guidelines and Technical Basis" part of the standard? What is their purpose? They do provide a reasonable engineering practice explanation in several cases. In item (3), please strike "or by coordination requirements with other Protection Systems." 4) The evidentiary requirements of this proposed standard greatly exceed those of the present standard, and rigid timelines are required. Entities need more time to make software changes, increase and train staff, and implement processes. Please change implementation to 'first day… 6 months after applicable regulatory approval'. 5) The standard and implementation plan should also exclude UFLS. Add 'Underfrequency Load Shedding' in 4.2.2.
Response: Thank you for your comment. **1. Thank you for your comment.** **2. Thank you for your comment.** **3. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the**		

Organization	Yes or No	Question 9 Comment
standard is not mandatory or enforceable. **4. The drafting team agreed and changed the effective date to twelve months after applicable regulatory approval.** **5. UFLS Misoperations are not covered by existing NERC standards.**		
Utility Services, Inc.		While we understand the need to move the Standards Development process on a faster pace, aka Rapid Development process; Utility Services feels that the RD p should not have the initial standard language drafted by RD p group. The SDT should be the group to draft the initial requirements. As outlined in the ROP, industry should be leading this effort.
Response: Thank you for your comments. **The drafting team forwarded your comment to the NERC Standards Committee and NERC staff.**		
American Electric Power		1. Why is it necessary to have PRC-004 along with both PRC-006 and PRC-016? It is not clear why these cannot also be addressed in this revision process, as for AEP, it would seem to be a natural extension of these responsibilities. 2. We suggest there should there be an explicit requirement regarding reporting, rather than providing this detail within the Compliance section. 3. It is not clear how much flexibility, if any, there is in completing investigative work in a timetable as required by R 1.5. For example, due to outages or required maintenance activities, one might not be able to meet the date as set within the timetable, which would require a new proposed completion date. If one were to be held to the standard "literally", is it even allowable to complete the work early? Though the application guide seems to partially address allowing changes to the CAP, the standard should be more explicit in doing so.
Response: Thank you for your comments. 1. **Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by any existing NERC standards.** 2. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged**		

Organization	Yes or No	Question 9 Comment
drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information". 3. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
American Transmission Company, LLC		
CenterPoint Energy		CenterPoint Energy recommends that Under Frequency Load Shedding programs be excluded from this standard. In the Applicability section of PRC-004-3, 4.2.2 should be written as follows: "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs (UFLS), and Under Voltage Load Shedding programs (UVLS) are excluded from this standard."
Response: Thank you for your comment. **UFLS Misoperations are not covered by any existing NERC standards.**		
BGE	No	No comment.
Consumers Energy	Yes	1) The reporting template describes several types of events that are "not reportable Misoperations". These types of events should also be specifically excluded in the standard, especially operations that occur during on-site activities. 2) The Effective Dates, listed in the Implementation Plan, are confusing as written. We suggest "first day of the first calendar quarter, at least 3 months after..." 3) Section 4.2.1 of the Applicability indicates the Standard is applicable to "Protection Systems". Since Protection System is capitalized, this indicates it is defined in the NERC Glossary. Is the intent of this standard to be inclusive of all protection system components (relays, cts, vt, dc circuits, and station batteries)? 4) In M2 remove "written lists". We are suggesting that no reference be made to lists.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1. The SDT has modified the definition of Misoperation to address on-site activities."** **2. Thank you for your suggestion. The drafting team changed the effective date to twelve months after applicable regulatory approval.** **3. Yes.** **4. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements. Lists are one of the acceptable forms of evidence.**		
ITC		Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the first or second half of the year.
Response: Thank you for your comment. **The drafting team retained the quarterly reporting period for Protection System Misoperation(s).**		
Wisconsin Electric		
Duke Energy	Yes	1. We like having the "Guidelines and Technical Basis" as part of the standard. For clarity, revise the third paragraph under Section 5 of the "Guidelines and Technical Basis" as follows: Failure to automatically reclose after a fault is not included as a Protection System Misoperation because reclosing equipment is not included under the definition of Protection Systems. Further, operations which are initiated by control systems (not by Protection Systems), such as those associated with generator and excitation controls, protection used during generator startup and shutdown (such as reverse power relaying), or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are also not Misoperations of a Protection System. 2. The requirements to have documented processes for identifying, analyzing and reporting Misoperations as well as CAP and action plan tracking may impact some entities. For such entities, the Implementation Plan may not allow sufficient time to both develop and implement additional processes.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1. The SDT revised the Guidelines and Technical Basis section to include more explanation.** **2. The drafting team agreed and changed the effective date to 12 months after applicable regulatory approval.**		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro	Yes	BC Hydro requests clarification for underfrequency load shedding schemes (UVLS). Would they fall under this standard?
Response: Thank you for your comment. **The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by any existing NERC standards.**		

10. **In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).**

If you have any comments on the draft SAR, please provide them here.

Summary Consideration:

A commenter had a concern with reviewing each Protection System operation. The SDT believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Measure M1 has been modified and provides examples of acceptable evidence to satisfy the review of operations Requirement. The SDT believes the review of Protection System operations is being performed already and just needs to be formally documented.

A commenter stated they believe that having a Misoperation makes them non-compliant. A Misoperation is not a violation of PRC-004 regardless of the cause. The purpose of PRC-004 is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.

A request was made to add Protection System operation review to the Title and Purpose of the standard. The SDT disagrees because the focus is Misoperation identification and mitigation.

One commenter wanted to be exempt from this standard because they are a nuclear generator operator and fall under NRC rules. The NRC requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council		
Public Service Enterprise		

Organization	Yes or No	Question 10 Comment
Group Company		
Hydro One		
Tri-State Generation and Transmission Ass'n - System Protection		None
FirstEnergy		
Pepco Holdings Inc Affiliates		
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team		
MRO's NERC Standards Review Forum		
Electric Market Policy		See response to Question 6 above.
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members		
PPL Generation		

Organization	Yes or No	Question 10 Comment
Florida Municipal Power Agency		1) A concerning statement in the SAR is the proposal to add a requirement to the standard to: "Review all Faults or Protection System operations on the BES to identify those that are BES Protection System Misoperations". We are uncomfortable with the word "review". We would imagine only those protection system operation that fell outside of a certain tolerance would need to be reviewed, e.g., more than one Element tripped, the trip took longer than X cycles, a trip happened without a fault, etc. Review implies something more than looking to see if a criteria was met for further review. So, does review mean to evaluate whether certain criteria was met, or to do a thorough review? We're concerned with the administrative burden of having to do more than a high level review for each and every protection system operation or fault. 2) What sort of evidence would be required to prove that we looked at every Protection System operation and fault on the BES? 3) This could create an unnecessary administrative burden on the industry. 4) Also, in the white paper, the paper identifies incorrect settings as a misoperation (see Table 2 on Cause Codes). To us, incorrect setting is not a misoperation and to call it such creates double jeopardy. If an engineer calculates the incorrect setting for a relay, that should be a PRC-001 standard implication. If a relay tech puts the wrong setting in the relay and tests to that wrong setting that should be a PRC-005 issue, and not a PRC-004 issue.
Response: Thank you for your comments. **1) The Standard Drafting Team believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Your method of review seems acceptable but compliance review is up to each Regional Entity.** **2) Measure M1 has been modified and provides examples of acceptable evidence to satisfy Requirement R1.** **3) The SDT believes this review is being performed already and just needs to be formally documented.** **4) The SDT disagrees. A Misoperation is not a violation of PRC-004-3 regardless of the cause. The purpose of PRC-004-3 is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.**		
Bonneville Power Administration		

Organization	Yes or No	Question 10 Comment
Western Area Power Administration		
Westar Energy		
Georgia Transmission Corporation		
PacifiCorp		No comments.
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.		
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie		No comment
Ingleside Cogeneration LP		
Oncor Electric Delivery		
Private Citizen		I'm not in the industry anymore, but I think the SAR assumes things that are not truly agreed upon by the industry. My comments are as follows: 1) Review all BES faults/operations - see my comments in Q9. 2) I do not believe the industry is in agreement that all operations need to be reviewed. Presumably, one could review a sub-set and capture the vast majority of potential Misoperations. This would be a better use of resources. So, my complaint here is that the SAR should not tie the hands of the drafting team by requiring that all operations are

Organization	Yes or No	Question 10 Comment
		reviewed unless it makes sense. 3) CAPs - again, see my comments in Q9. I'm unconvinced that you need lots of rules for CAPs. I think a performance requirement would be a better way to go. My complaint here is that it is too prescriptive. Again, the hands of the drafting team should not be tied like this.
Response: Thank you for your comments. **1) See the SDT response to your comment in Q9.** **2) The Standard Drafting Team believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Review of a subset of all operations, while probabilistically significant, would not serve reliability properly. The SDT believes this review is being performed already and just needs to be formally documented.** **3) See the SDT response to your comment in Q9. If a Misoperation occurs, it needs to be corrected and documented in a Corrective Action Plan. The SDT believes the SAR is not too prescriptive regarding Corrective Action Plans.**		
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
PSE		Combining similar standards and clarifying definitions or requirements is always good. Thanks for the effort.
Response: Thank you for your comment.		
TransAlta		1) The Standard title would be: Protection System Operation Analysis and Protection System Misoperation Identification and Correction 2) The Purpose of this standard would be: Analyze the causes of operation of BES Protection systems and identify and correct the causes of Misoperation of BES Protection Systems.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comments. **1. The SDT believes the title is adequate.** **2. The SDT believes the purpose correctly defines the reliability goal of the standard.**		
Entergy Services		
GenOn Energy		
Indiana Municipal Power Agency		no comments
Exelon		Exelon Nuclear: Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Response: Thank you for your comments. **These requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.**		
Manitoba Hydro		

Organization	Yes or No	Question 10 Comment
Tacoma Power		None
Ameren		
Utility Services, Inc.		
American Electric Power		
American Transmission Company, LLC		
CenterPoint Energy		
BGE		No comment.
Consumers Energy		
ITC		1) Suggest changing the first bullet to begin "Review all Faults or outages caused by Protection System operations…". 2) The draft standard 4.2.2 indicates that SPS, RAS and UVLS programs are excluded and this should also be indicated in the SAR.
Response: Thank you for your comments. **1) The SDT removed BES Faults from the requirements because review of all Protection System operations would include Faults and some operations/Misoperations do not involve Faults. All Protection System operations should be reviewed because their cause could be a fault, or the outage could be caused by a Protection System Misoperation.** **2) The SDT disagrees. The SAR is larger in scope while the Applicability section of the standard sets limits.**		
Wisconsin Electric		
Duke Energy		

Organization	Yes or No	Question 10 Comment
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

END OF REPORT

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. The SAR posted for informal comment June 10, 2011 through July 11, 2011.
2. SC authorized moving the SAR forward to standard development at the June 9, 2011 meeting.
3. First posting of Draft Version 1 on June 10, 2011 with a comment period closed on July 11, 2011.

Description of Current Draft

This is a 45 day formal comment period with parallel initial ballot.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July, 2012
Recirculation ballot	October, 2012
BOT Approval	November, 2012

Effective Dates: First day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking

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 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

Failure of a Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault** - A failure of a Protection System to operate for a Fault within the zone it is designed to protect. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

2. **Failure to Trip - Other Than Fault** - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

3. **Slow Trip - During Fault** - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)

4. **Slow Trip** - **Other Than Fault** - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.

6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, construction or commissioning activities.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.
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 for Facilities that are part of the BES

4.2.2 Facilities not included

4.2.2.1 Special Protection Systems (SPS) or Remedial Action Schemes (RAS)

4.2.2.2 Undervoltage Load Shedding (UVLS)

4.2.3 Relay functions not included (these are non-protective functions that may be imbedded within a Protection System)

4.2.3.1 Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)

4.2.3.2 Automation (e.g. data collection)

Applicability: SPS and RMS schemes are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion of the automation portion of relays are excluded from this standard.

5. Background:

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

Misoperation data, as currently collected and reported, is not usable to establish a consistent metric for measuring Protection System performance. The SAR includes establishing a standard with uniform applicability, revising the definition of Misoperation, and clarifying reporting requirements.

The proposed requirement of the revised Reliability Standard PRC-004-3 meets the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.

- Analyze Misoperations Protection Systems for Facilities that are part of the BES to determine the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations of or associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding are not addressed in this standard due to their inherent complexities. NERC intends to address these areas through future projects.

Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

B. Requirements and Measures

R1. Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 Identify and review each Protection System operation. If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information.

1.2 Designate each Misoperation (if any).

1.3 Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1

Rationale for R1: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The SDT believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.

that may include, but is not limited to, dated lists, logs, or a database that documents the date and time of each interrupting device operation and an indication when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal and receipt of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database that documents the date, time, Facility and equipment name associated with each Misoperation. Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of a dated investigation report or documented findings for each Misoperation.

R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.

Rationale for R2: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close out the Misoperation investigation process and future reference.

R3. For each Misoperation without an identified cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated interrupting device operation, complete: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or
- A declaration explaining why no further actions will be taken.

Rationale for R3: Where a Misoperation cause is not determined during the investigation, implementing an action plan of additional investigation/monitoring may determine a cause. The 180 calendar days is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

If the investigation does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close out the Misoperation investigation process and future reference.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R3 that must include a dated action plan or a dated declaration.

R4. For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider shall: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]*

4.1 Implement the CAP or action plan

4.2 Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion

Rationale for R4: The CAP or action plan must be fully implemented to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, completion of actions and revisions for each CAP or action plan; dated work management program records, dated work orders, or dated maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

- Regional Entity or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.

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 that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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 Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA within two calendar months following the end of each calendar quarter.

The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Assessment, Operations Planning**	**Medium**	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 120 calendar days but less than or equal to 130 calendar days of the operation's occurrence. OR The responsible entity identified a Protection System operation that operated one of its interrupting devices but failed to review the operation in	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 130 calendar days but less than or equal to 140 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 140 calendar days but less than or equal to 150 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 150 calendar days of the operation's occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its interrupting devices in accordance with Requirement R1, Part

			accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System Operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.3.			1.1. OR The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2. OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.3. OR The responsible entity completed its investigation of a Protection System

						Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's Protection System component contributed to the Misoperation, and failed to notify and provide requested investigative information to that entity in accordance with Requirement R1, Part 1.1.
R2	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the completion of the investigation or receiving notification. OR The responsible entity failed to develop a CAP or make a declaration in accordance with

						Requirement R2.
R3	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to 190 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 190 calendar days but less than or equal to 200 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 200 calendar days but less than or equal to 210 calendar days following the completion of the investigation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than 210 calendar days following the completion of the investigation. OR The responsible entity failed to develop, implement, and documented an action plan, or a declaration in accordance with Requirement R3.
R4	**Operations Planning, Long-Term Planning**	**High**	The responsible entity maintained records of a CAP or action plan but the records were incomplete.			The responsible entity failed to implement a CAP or action plan. OR The responsible entity failed to maintain records of a CAP or action plan.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

A revised Misoperation definition is being proposed for industry adoption. It includes the following conditions:

(1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. A lack of target information, e.g. when a high-speed pilot system does not trip because a high-speed zone element trips first, is not a Misoperation. If a fault or abnormal condition is cleared within the time normally expected with proper functioning of at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation.

(2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation.

(3) A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems.

(4) A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate. An example of this type of Misoperation is an over excitation condition where the protection designed to detect this condition operated slower than intended resulting in a higher degree of insulation stress than desired.

(5) A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. An example of this type of Misoperation is an over-reaching trip due to a lack of coordination between remote and local Protection Systems. Note: Operation of properly coordinated remote Protection Systems to clear the Fault in adjacent zones is not a Misoperation of the remote Protection System if the local Protection System of the faulted Element fails to clear the Fault within the intended time; however, the failure of the local Protection System for the faulted zone is a Misoperation.

(6) A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate. These non-Fault conditions may include power swings, over excitation or loss of excitation but could include even normal conditions. For example, a relay failure during normal conditions could conceivably cause an incorrect trip and a Misoperation. In a second example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation. In a third example, an impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because it was set with an excessive reach that unnecessarily restricted the line's load carrying capability. This category of Misoperation cannot address at this time other operations during power swings unless the relay is clearly improperly set. Additional clarity on this specific issue will need to await completion of Phase III of Project 2010-13 on Relay Loadability which will address protective relay operations due to power swings as directed by FERC Order No. 733. Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning.

This definition is based on the established IEEE/PSRC I3 Working Group on ‘Transmission Protective Relay System Performance Measuring Methodology’ categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with “non-fault condition” to remove ambiguity.

Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.

Interrupting Device operations which are initiated by control systems, such as those associated with generator controls, or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.

A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation. These types of operations are excluded because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not Misoperations. Protection System operations which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.

In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line’s relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.

This standard addresses the reliability issues identified in the letter from Gerry Cauley, NERC President and CEO, dated January 17, 2010. “Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events…….. Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations.” The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance; July 2011 “….a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.

Requirement R1

This requirement promotes the prudent evaluation of all Protection System operations to designate Misoperations, even those difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed Faults resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

Requirement 1 places the responsibility on the interrupting device owner to investigate operations initiated by a Protection System. The SDT believes the owner of the interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the interrupting device owner suspects that the Misoperation was caused by a Protection System component owned by another entity, they must notify that component owner and document the notification. In this case, it is expected that both entities will work together to investigate the cause of the operation.

Protection Systems are made of many components. These components may be owned by more than one entity. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation.

Determining the cause of Protection System Misoperations is essential in developing an effective remedy to avoid future Misoperations. The SDT believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in an investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.

Regardless of whether a cause is identified, the interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a single Protection System causes multiple interrupting device owners to be affected, the entities may work together to produce a common investigation report. Similarly, if the interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report. Each TO, GO, or DP would be expected to have a copy of the common investigation report.

An investigation report may include the following information: 1) initial evidence, 2) probable causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records. Probable causes are those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the cause. The conclusions should summarize the cause(s) substantiated by the evidence and findings of the tests and studies.

Requirement 2

If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP, or to prepare a declaration justifying the lack of a CAP.

Where there are multiple Protection System owners involved in a Misoperation, the one or more owners whose Protection System component(s) contributed to the Misoperation will create a CAP or declaration as required by Requirement 2. Owners whose Protection System components operated correctly do not need to create a CAP. All owners should update their investigation documentation to indicate which party or parties are performing a CAP to address the Misoperation.

Resolving Misoperations benefits the Protection System owner and the BES by improving reliability and security. The CAP is an established tool for resolving operational problems. The NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".

Protection System owners are expected to exercise due diligence in the development and implementation of a CAP. Typically included would be any corrective actions taken to prevent recurrence (along with the date performed), and any corrective actions planned to be taken to prevent recurrence (along with the planned date).

An example of a CAP for a Misoperation determined to have been caused by a failed relay that has not been repaired might be: "Temporarily removed failed relay from service on xx/xx/xx. Plan to repair then return relay to service on xx/xx/xx."

An example of a CAP for a Misoperation determined to have been caused by a failed relay that has been repaired might be: "Temporarily removed failed relay from service on xx/xx/xx. Repaired then returned relay to service on xx/xx/xx."

An example of a CAP for a Misoperation suspected to have been caused by an intermittent relay failure might be: "Temporarily removed suspect relay from service on xx/xx/xx. Replaced with like kind, and placed in service on xx/xx/xx."

If the Misoperation cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners are required to make a declaration to this effect. A "no CAP declaration" would typically include the Misoperation cause and justification for taking no corrective action.

An example of a "no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is expected to be used sparingly.

CAPs should include an evaluation as to whether the entity's Protection Systems at other locations are also vulnerable to the same type of Misoperation.

Requirement 3

If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).

At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.

An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."

An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."

An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review by xx/xx/xx."

If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this effect. A "no action plan declaration" would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.

An example of a "no action plan declaration" might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."

Requirement R4

Finally, the goal of the standard has not been met unless CAP(s) or action plans are actually implemented, as is required in Requirement R4. The responsible entity is required to implement and complete a CAP or action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The responsible entity is also required to complete the CAP or action plan, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement 2. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.

Reporting:

A review of the Transmission Availability Data System (TADS) data for the years 2008 – 2010 revealed that the fourth ranked initiating cause of BES outages not related to weather was “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.

Section C-1.4 requires periodic data reporting and references a common reporting format to facilitate consistent reporting of Misoperation data by all Transmission Owners, Generator Owners, and Distribution Providers. Reporting Misoperation data in a common format permits the ERO to analyze the data, develop meaningful metrics for measuring Protection System performance, identify trends in Protection System performance that negatively impact reliability, and identify lessons learned.

Analysis of data from all Misoperations across North America makes possible identification of issues and trends that may not be identifiable through analysis of smaller data sets on an entity or regional basis. Information regarding identified issues and trends and recommended actions will be shared with Transmission Owners, Generator Owners, and Distribution Providers through lessons learned or industry alerts. Sharing this information will permit recipients to take appropriate actions to drive improvements in Protection System performance.

The common reporting template also will improve the usefulness of metrics developed to track Protection System performance. While the most relevant category defined in TADS is titled "Failed Protection System Equipment," the title is not an accurate description of the information reported in the metric. This metric includes all Protection System Misoperations that are not related to human error, which is only a subset of all Protection System Misoperations. The Protection System Misoperations related to human error (e.g., miscoordinated settings, incorrect setting calculations, and errors in applying settings to the relay, etc.) are tracked separately from Protection System equipment-related Misoperations, and are grouped together with other human errors by a utility employee or contractor. Similarly, Protection System Misoperations related to failed equipment such as a failed CVT on the primary insulation side are reported under "Failed AC Substation Equipment." Reporting of Misoperations data using the common format specified in C-1.4 will permit development of metrics specific to Protection System Misoperations, with the potential to break down the metric by category of Misoperation (e.g., failure to trip, slow trip, unnecessary trip, etc.) and cause of Misoperation (ac system, dc system, as-left personnel error, incorrect setting/logic/design, and relay failures/malfunctions).

Reporting Misoperations and their CAPs or action plans provides a means of monitoring and assessing Misoperations. Reviewing and tracking this information provides a method of validating the actions taken to address the causes of Misoperations. A second need for reporting Misoperations is to facilitate the identification of trends in Protection System performance that negatively impact reliability. Analyzing data from all Misoperations across North America will make it possible to identify trends that may not be discernible through analysis of smaller data sets on an entity or regional basis.

Misoperations and updates will be submitted to the Regional Entity on a quarterly basis per the following schedule:

Reporting Quarter	**Submission Date**
1st Quarter (Jan 1 – March 31)	May 31
2nd Quarter (Apr 1 – June 30)	August 31
3rd Quarter (July 1 – Sept 30)	November 30
4th Quarter (Oct 1 – Dec 31)	February 28

The two calendar months reporting of Misoperations that occurred within the quarterly reporting period corresponds to the recommendations provided by ERO-RAPA and also correlates to the time which the majority of Regional Entities were using in 2011. It is believed that two calendar months is a reasonable time for an entity to submit their Misoperations data after the close of a reporting period. Reporting and updating on a limited time interval and lag (from occurrence) aids in focusing on high trend items of common mode failures. A longer period of time for reporting could prevent high trend failures from being quickly recognized.

Examples of reporting:

1. If a Misoperation occurred on March 30 but was not identified as a Misoperation until June 2, then this Misoperation would be reported in the second quarter reporting period.
2. If the Misoperation in example 1 was not completely investigated in the second quarter but a cause was determined on July 2, then a resubmittal should be reported in the third quarter.
3. If the Misoperation in examples 1 and 2 had its CAP completed on November 2, then a resubmittal indicating that the CAP was completed should be reported in the fourth quarter.

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. The SAR posted for informal comment June 10, 2011 through July 11, 2011~~(Dates of posting)~~.
2. SC authorized moving the SAR forward to standard development ~~(SC meeting date when authorized).~~at the June 9, 2011 meeting.
3. ~~2.~~3. First posting of Draft Version 1 on June 10, 2011 with a comment period closed on July 11, 2011.

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,~~This is a 45 day formal comment period with parallel initial ballot~~, 30-day formal comment period with parallel successive ballot, recirculation ballot)~~.

Anticipated Actions	Anticipated Date
~~30-day Formal Comment Period~~	~~June 9, 2011~~
45-day Formal Comment Period with Parallel Initial Ballot	~~September 16, 2011~~July, 2012
Recirculation ballot	~~December 19, 2011~~October, 2012
BOT ~~adoption~~Approval	~~February 13~~November, 2012

Effective Dates: ~~Requirement R1 and its associated parts shall become effective on the first~~First day of the first calendar quarter~~, 3~~ that is six months ~~after~~beyond the date that this standard is approved by applicable regulatory ~~approval. In~~authorities, or in those jurisdictions where ~~no~~ regulatory approval is not required, ~~all requirements go into effect on~~ the standard becomes effective on the first day of the first calendar quarter~~, 3~~ that is six months ~~after~~beyond the date this standard is approved by the NERC Board of Trustees ~~adoption~~, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking

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 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

Failure of a Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault** - ~~Any~~A failure of a Protection System to operate for a Fault within the zone it is designed to protect. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

2. **Failure to Trip - Other Than Fault** - ~~Any~~A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power ~~swings~~swing, under-voltage, over excitation, or loss of excitation~~ for which the Protection System was intended to operate. ~~. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

3. **Slow Trip -** ~~Any~~**During Fault** - A Protection System operation that is slower than ~~planned~~intended for a Fault within the zone it is designed to protect. ~~-~~(Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)

~~4.~~ ~~**Unnecessary**~~**Slow Trip** - ~~**During**~~**Other Than Fault** - ~~Any~~A Protection System operation ~~for a Fault not within the zone it is designed to protect.~~

~~5.~~4. ~~**Unnecessary Trip - Other Than Fault** - Any Protection System operation for~~ that is slower than intended for a non-Fault ~~conditions~~condition such as a power ~~swings~~swing, under-voltage, over excitation, or loss of excitation for which the Protection System ~~is not~~was intended to operate.

5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.

6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, construction or commissioning activities.

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 Misoperation Identification and Correction**

2. **Number:** PRC-004-3

3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.

4. **Applicability:**

> **Applicability:** SPS and RMS schemes are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion of the automation portion of relays are excluded from this standard.

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 for Facilities that are part of the BES~~.~~

4.2.2 Facilities not included

4.2.2.1 Special Protection Systems (SPS~~),~~) or Remedial Action Schemes (RAS~~), and Under Voltage~~)

4.2.2.2 Undervoltage Load Shedding ~~programs~~(UVLS)

~~**4.2.2**~~**4.2.3** Relay functions not included (these are ~~excluded from this standard.~~non-protective functions that may be imbedded within a Protection System)

4.2.3.1 Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)

4.2.3.2 Automation (e.g. data collection)

5. **Background**:

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. ~~In FERC Order No. 693 (dated March 16, 2007),~~PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation

Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-~~1~~0 as a ~~"~~fill-in-the-blank~~"~~ standard~~ and did not approve or remand the standard since~~. The NOPR stated that because the regional procedures had not been submitted~~.~~

~~Since~~, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is ~~no~~not a mandatory requirement for ~~the~~ Regional ~~Entity~~ procedures to support the requirements of PRC-004-~~2~~2a. This ~~represents~~is a potential reliability gap~~. ~~; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

Misoperation data, as currently collected and reported, is not usable to establish a consistent metric for measuring Protection System performance. The SAR includes establishing a standard with uniform applicability, revising the definition of Misoperation, and clarifying reporting requirements.

The proposed requirement of the revised Reliability Standard PRC-004-3 meets the following objectives:

- Review all ~~Faults and~~ Protection System operations on the BES to identify those that are ~~BES Protection System~~ Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze ~~BES Protection System~~ Misoperations Protection Systems for Facilities that are part of the BES to determine the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of ~~BES Protection System~~ Misoperations of Protection Systems for Facilities that are part of the BES.

~~The reporting of~~ Misoperations of or associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding ~~has~~are not ~~been~~ addressed in this standard due ~~the complexity of the subject matter.~~to their inherent complexities. NERC intends to address these areas through ~~a separate project in the~~ future projects.

Note that ~~there are two~~the WECC ~~standards, PRC-003-STD-1 and~~Regional Reliability Standard PRC-004-WECC-1~~, related~~ relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where ~~those standards will overlap~~PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard. ~~Doing so will ensure compliance with the less stringent standard as well. There are no apparent conflicts between the standards that would lead to mutually exclusive compliance.~~

B. Requirements and Measures

R1. ~~Each~~Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall ~~have and implement a procedure to identify and address all Protection System Misoperations within its system. At a minimum, the procedure shall include~~: *[Violation Risk Factor: ~~High~~] [Medium][Time Horizon: Operations Assessment, Operations Planning]*

Rationale for R1: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The SDT believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.

~~**1.1** A detailed description of the processes used to:~~

~~**1.1.1** Document and review all BES Faults and BES Protection System operations.~~

~~**1.1.2** Identify and document all associated Misoperations, if any.~~

~~**1.1.3** Investigate and address each Misoperation.~~

~~**1.2** A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s) and do one of the following:~~

1.1 ~~For~~Identify and review each Protection System operation. If the entity suspects a Protection System component(s) owned by another entity contributed to a

Misoperation, notify the owner of that Protection System component and provide any requested investigative information.

1.2 Designate each Misoperation ~~where the cause(s) are identified, document the investigation and the cause(s~~(if any).

1.3 ~~For those cases where the cause(s) are not identified,~~ Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1 that may include, but is not limited to, dated lists, logs, or a database that documents the date and time of each interrupting device operation and an indication when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal and receipt of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database that documents the date, time, Facility and equipment name associated with each Misoperation. Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of a dated investigation~~, any cause(s) that were ruled out, and any additional steps planned to identify the cause(s).~~ report or documented findings for each Misoperation.

~~**1.3** A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days of the Misoperation, develop one of the following:~~

~~**Rationale for R1**: This requirement mandates entities have a process to identify and correct Protection System Misoperations. A review of the Transmission Availability Data System (TADS) data for the past three years reveals that the fourth ranked initiating cause of BES outages not related to weather is "Failed Protection System Equipment." By developing more structure regarding the manner in which Misoperations are identified and corrected, risks to the BES caused by Misoperations can be reduced by ensuring that certain mandatory practices are consistently undertaken. Further, such consistency will also enhance reporting and the development of performance metrics that indicate overall system health, as well as facilitate the sharing of "lessons learned."~~

R2. ~~A~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes~~:~~ an evaluation of the CAP's

Rationale for R2: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close out the Misoperation investigation process and future reference.

applicability to the entity's Protection Systems at other locations, or

~~1. Interim~~Explain in a declaration why corrective actions ~~(if any).~~

- ~~Final corrective or mitigating actions to~~are beyond the entity's control or would reduce ~~potential impacts to~~ BES reliability.

~~2. A work timetable.~~

~~A~~ **M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.

~~A requirement that for all Misoperations for which the cause(s) was (were) not~~

R3. For each Misoperation without an identified~~, the Registered Entity~~ cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within ~~120~~180 calendar days of the ~~Misoperation, develop one~~associated interrupting device operation, complete: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

Rationale for R3: Where a Misoperation cause is not determined during the investigation, implementing an action plan of additional investigation/monitoring may determine a cause. The 180 calendar days is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

If the investigation does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close out the Misoperation investigation process and future reference.

~~1.4~~ Development of ~~the following:~~

- ~~An~~an action plan that identifies~~:~~
  - ~~Additional~~ any additional investigative actions and/or Protection System modifications~~.~~, including a work timetable, or
    1. ~~A work timetable.~~
  - A declaration ~~that includes an explanation of~~explaining why no further ~~investigation or~~ actions will be taken.

~~1.5 A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented.~~

~~**M1.** The~~**M3.** Each Transmission Owner, Generator Owner ~~and Distribution Provider shall have a current copy of its procedure for identifying and addressing Misoperations in accordance with Requirement R1.~~

~~**M2.** The Transmission Owner, Generator Owner~~, and Distribution Provider shall have ~~dated written lists of Faults, Protection System operations, and identified Misoperations with their associated date of occurrence to demonstrate implementation of the procedural elements related to~~ evidence for Requirement ~~R1, Part 1.1.~~

~~**M3.** The Transmission Owner, Generator Owner and Distribution Provider shall have a dated written investigation report for each Misoperation identifying either cause(s), or where the cause(s) of the Misoperation cannot be identified, any additional steps planned for identifying causes to demonstrate implementation of the procedural elements related to Requirement R1, Part 1.2.~~

~~**M4.** To demonstrate implementation of the procedural elements related to Requirement R1, Part 1.3, the responsible entity shall have, for each Misoperation with an identified cause or causes, a dated CAP or a dated written declaration explaining why there is no need to develop a CAP.~~

~~To demonstrate implementation of the procedural elements related to Requirement R1, Part 1.4, the responsible entity shall have, for each Misoperation without an identified cause~~

~~or causes, a dated written action plan that includes a work timetable for implementation or~~ R3 that must include a dated ~~written~~ action plan or a dated declaration ~~explaining why no further investigation or actions will be taken.~~ .

R4. ~~The responsible entity~~For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider shall: [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]*

4.1 Implement the CAP or action plan

4.2 Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion

Rationale for R4: The CAP or action plan must be fully implemented to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have ~~dated~~ evidence~~, such as~~ for Requirement R4 that must include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, completion of actions and revisions for each CAP or action plan; dated work management program records ~~or~~, dated work orders ~~or other dated evidence, to demonstrate implementation of any plans completed during the implementation of the procedural elements related to Requirements R1, Part 1.5~~, or dated maintenance records.

~~**M5.** The responsible entity shall have dated documentation that describes the manner in which the each CAP or action plan was completed to demonstrate compliance with the procedural elements related to Requirements R1, Parts 1.5~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

~~Regional Entity~~

- Regional Entity or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.

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 ~~each~~ Distribution Provider that owns a BES Protection System shall ~~retain~~keep data or evidence to show compliance with ~~Requirement~~Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, ~~M5, M6, and M7 for six calendar years~~since the last audit unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~The Compliance Monitor shall retain any audit data for six years.~~

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System is found non-compliant, it shall keep information related to the non-compliance until ~~found compliant~~mitigation is complete and approved, or for the time specified above, whichever is longer.

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 Audit

Self-Certification

Spot Checking

Compliance ~~Violation~~ Investigation

Self-Reporting

~~Complaints~~

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

~~***Periodic Data Submittal:*** Within 60 calendar days following the end of each calendar quarter, each~~ Each Transmission Owner, Generator Owner, and ~~each~~ Distribution Provider that owns BES protection Systems will submit ~~a quarterly report to its Regional Entity that lists all Protection System Misoperations~~the data identified in ~~accordance with Requirement R1 using~~ PRC-004 - Attachment 1 to the ~~format specified by the ERO. Each responsible entity will include the status of each of its Misoperation CAPs or action plans developed until these CAPs or action plans are reported complete~~CEA within two calendar months following the end of each calendar quarter.

The ~~Regional Entity~~CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Assessment, Operations Planning**	~~High~~Medium	The responsible entity ~~documented~~performed the ~~investigation and either identified the cause or listed the additional steps planned to identify the cause~~actions in ~~more than 90 calendar days but less than or equal to 120 calendar days~~	The responsible entity ~~documented~~performed the ~~investigation and either identified the cause or listed the additional steps planned to identify the cause~~actions in accordance with Requirement R1, Parts 1.1 – 1.3 in	The responsible entity ~~documented~~performed the ~~investigation and either identified the cause or listed the additional steps planned to identify the cause~~actions in accordance with Requirement R1, Parts 1.1 – 1.3 in	The responsible entity ~~did not have a procedure to identify and address all Protection System Misoperations~~performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 150 calendar days of the operation's occurrence. OR The responsible entity failed to ~~implement~~identify and review a Protection System operation that operated one of its ~~procedure to identify and address all Protection System Misoperations~~interrupting devices in accordance with Requirement R1, Part 1.1.

			~~following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented a CAP or a declaration~~accordance with Requirement R1, Parts 1.1 – 1.3 in more than 120 calendar days but less than or equal to ~~150~~130 calendar days ~~following~~of the ~~Misoperation~~operation's occurrence.	more than ~~120~~130 calendar days but less than or equal to ~~130~~140 calendar days ~~following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented a CAP or a declaration in more than 150 calendar days but less than or equal to 160 calendar days following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented a CAP but failed to include one~~ of the ~~elements listed in Requirement R1, Part 1.3.~~	more than ~~130~~140 calendar days but less than or equal to ~~140~~150 calendar days ~~following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented a CAP or a declaration in more than 160 calendar days but less than or equal to 170 calendar days following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented a CAP but failed to include two~~ of the ~~elements listed in Requirement R1, Part 1.3.~~	OR The responsible entity ~~documented the investigation and either identified the cause or listed~~completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the ~~additional steps planned to identify the cause in more than 140 calendar days following the~~ operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2. OR The responsible entity failed to investigate a Misoperation and document the ~~investigation and identify the cause or list the additional steps planned to identify the cause~~findings in

			OR The responsible entity ~~developed and documented an action plan or~~identified a ~~declaration~~Protection System operation that operated one of its interrupting devices but failed to review the operation in ~~more than~~accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System Operation that operated one of its interrupting devices in 120 calendar days ~~but less than or equal to 150 calendar days following the~~ and determined the operation was a Misoperation~~.~~	~~OR~~ ~~The responsible entity developed and documented an action plan or a declaration in more than 150 calendar days but less than or equal to 160 calendar days following the Misoperation.~~ operation's occurrence.	~~OR~~ ~~The responsible entity developed and documented an action plan or a declaration in more than 160 calendar days but less than or equal to 170 calendar days following the Misoperation.~~ ~~OR~~ ~~The responsible entity developed and documented an action plan but failed to include the delivery dates in accordance with the work timetable specified in Requirement R1, Part1.4.~~ ~~OR~~ ~~The responsible entity implemented the CAP or other action plan, but did not meet the completion timeline stated in the plan~~operation's occurrence.	accordance with Requirement R1, Part 1.3. OR The responsible entity ~~developed and documented~~completed its investigation of a ~~CAP or a declaration~~Protection System Operation that operated one of its interrupting devices in ~~more than 170~~120 calendar days ~~following~~ and suspected that another entity's Protection System component contributed to the Misoperation~~.~~ ~~OR~~ ~~The responsible entity~~, and failed to ~~develop and document a CAP or a declaration following a Misoperation.~~ ~~OR~~ ~~The responsible entity developed~~notify and

			and failed to document the findings in accordance with Requirement R1, Part 1.3.			~~documented an action plan or a declaration in more than 170 calendar days following the Misoperation.~~ ~~OR~~ ~~The responsible entity failed to develop and document an action plan or a declaration following a Misoperation.~~ ~~OR~~ ~~The responsible entity failed~~provide requested investigative information to ~~implement a CAP or other action plan~~that entity in accordance with Requirement R1, Part 1.1.
R2	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar

			more than 60 calendar days but less than or equal to 70 calendar days following the completion of the investigation or receiving notification.	more than 70 calendar days but less than or equal to 80 calendar days following the completion of the investigation or receiving notification.	more than 80 calendar days but less than or equal to 90 calendar days following the completion of the investigation or receiving notification.	days following the completion of the investigation or receiving notification. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.
R3	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to 190 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 190 calendar days but less than or equal to 200 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 200 calendar days but less than or equal to 210 calendar days following the completion of the investigation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than 210 calendar days following the completion of the investigation. OR The responsible entity failed to develop, implement, and documented an action plan, or a declaration in accordance with Requirement R3.
R4	**Operations Planning, Long-Term Planning**	**High**	The responsible entity maintained records of a CAP or action plan but the records were			The responsible entity failed to implement a CAP or action plan.

			incomplete.			OR The responsible entity failed to maintain records of a CAP or action plan.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

A revised Misoperation definition is being proposed for industry adoption. It includes the following conditions:

(1) ~~Any~~A failure of a Protection System to operate for a Fault within the zone it is designed to protect. A lack of target information, e.g. when a high-speed pilot system does not trip because a high-speed zone element trips first, is not a Misoperation. If a fault or abnormal condition is cleared within the time normally expected with proper functioning of at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation.

(2) ~~Any~~A failure of a Protection System to ~~trip~~operate for a non-Fault condition ~~such as power swings, over excitation, or loss of excitation~~ for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation.

(3) ~~Any~~A Protection System operation that is slower than ~~planned~~intended for a Fault within the zone it is designed to protect. Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems.

(4) ~~Any~~A Protection System operation that is slower than intended for a ~~Fault not within the zone it is~~ non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate. An example of this type of Misoperation is an over excitation condition where the protection designed to **~~protect.~~**detect this condition operated slower than intended resulting in a higher degree of insulation stress than desired.

(5) A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. An example of this type of Misoperation is an over-reaching trip due to a lack of coordination between remote and local Protection ~~System relays~~Systems. Note: Operation of properly coordinated ~~backup~~remote Protection ~~System relays~~Systems to clear the ~~fault~~Fault in ~~an~~ adjacent ~~zone~~zones is not a Misoperation of the remote Protection System if the ~~primary protection~~ local Protection System of the faulted Element fails to clear the ~~fault~~Fault within the ~~specified~~intended time; however, the failure of the local Protection System for the faulted zone is a Misoperation.

(~~5) Any~~6) A Protection System operation for a non-Fault ~~conditions such as power swings, over excitation, or loss of excitation~~condition for which the Protection System is not intended to operate. ~~For~~These non-Fault conditions may include power swings, over excitation or loss of excitation but could include even normal conditions. For example, a relay failure during normal conditions could conceivably cause an incorrect trip and a Misoperation. In a second example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation. In a third example, an impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because it was set with an excessive reach that unnecessarily restricted the line's load carrying capability. This category of Misoperation cannot address at this time other operations during power swings unless the relay is clearly improperly set. Additional clarity on this specific issue will need to await completion of Phase III of Project 2010-13 on Relay Loadability which will address protective relay operations due to power swings as directed by FERC Order No. 733. Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning.

This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.

Failure to automatically reclose after a ~~fault~~Fault is not included as a~~ Protection System~~ Misoperation because reclosing equipment is not included under the definition of Protection Systems. ~~Operations~~

Interrupting Device operations which are initiated by control systems~~ (not by Protection Systems),~~, such as those associated with generator controls, or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are ~~also not Misoperations of a Protection System~~not operations of a Protection System. Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.

~~**Requirement R1** states the overall objective of the standard, which is to ensure that entities have and consistently implement a procedure to identify and correct all Protection System Misoperations. Specific detail regarding what this procedure must include is provided in the **Parts 1.1 through 1.5**.~~

~~**Part 1.1** requires that entities have a process to review all events for potential Misoperations and identify all Misoperations found. Reviewing all events associated with Faults on the BES and reviewing all BES Protection System Operations is necessary for reviewing all events which may be associated with BES Protection System Misoperations. The process of identifying a Misoperation from an analytical standpoint begins with a review of all situations that challenge Protection Systems. Faults are one of the major sources of challenge to the BES Protection System. A fault does not need to occur on the BES to result in a BES Protection System Misoperation. To completely identify Misoperations, it must be determined if the Protection System operated for a Fault within its zone of protection, a Fault outside its zone, or a no-Fault condition.~~A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation. These types of operations are excluded because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not

Misoperations. Protection System operations which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.

In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.

This standard addresses the reliability issues identified in the letter from Gerry Cauley, NERC President and CEO, dated January 17, 2010. "Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events…….. Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations." The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance; July 2011 "….a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.

Requirement R1

This requirement promotes the prudent evaluation of all Protection System operations to designate Misoperations, even those difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed Faults resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

~~Given that a Misoperation has been identified, **Part 1.2** requires the responsible entity accurately identify the underlying or "root" cause in sufficient detail to develop a corrective action plan that remedies the problem to prevent Misoperation recurrence. The cause of most Misoperations can be identified without extraordinary effort. Where a cause cannot be identified, a thorough documentation of the investigation is required to aid future investigation of the Misoperation particularly if it recurs. It is expected that the responsible entity will perform due diligence to identify the Misoperation cause.~~

Requirement 1 places the responsibility on the interrupting device owner to investigate operations initiated by a Protection System. The SDT believes the owner of the interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the interrupting device owner suspects that the Misoperation was caused by a Protection System component owned by another entity, they must notify that component owner and document the notification. In this case, it is expected that both entities will work together to investigate the cause of the operation.

Protection Systems are made of many components. These components may be owned by more than one entity. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation.

Determining the cause of Protection System Misoperations is essential in developing an effective remedy to avoid future Misoperations. The SDT believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in an investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.

Regardless of whether a cause is identified, the interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a single Protection System causes multiple interrupting device owners to be affected, the entities may work together to produce a common investigation report. Similarly, if the interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report. Each TO, GO, or DP would be expected to have a copy of the common investigation report.

An investigation report ~~generally includes~~may include the following information: 1) initial evidence, 2) probable~~ or potential~~ causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records. ~~The probable (or potential)~~Probable causes are~~ a list of~~ those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests ~~(e.g.~~if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the ~~root~~ cause. The conclusions should summarize the ~~root~~ cause(s) substantiated by the evidence and findings of the tests and studies.

~~If no root cause was found, then the conclusions would attest to the indeterminate results and delineate those causes that have been eliminated.~~

Part 1.2 ~~gives 90 calendar days from the date of the Misoperation to complete the investigation. The 90 day allowance was selected to provide sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes.~~

~~This standard applies to all BES Protection Systems some of which are more critical than others. It is assumed that critical systems will be addressed with more urgency which may delay the investigation of less critical systems. Some regional standards (such as PRC-004-WECC-1) may identify those critical elements and provide more stringent time frames.~~

~~In most cases where a root cause of a Misoperation is identified, a Corrective Action Plan to address the cause will improve the performance and reliability of the BES.~~ ~~**Part 1.3, Bullet 1**~~ ~~establishes the need for an entity to have a procedure for developing Corrective Action Plans. A Corrective Action Plan should include interim corrective actions, final corrective actions, and a timeline for completion delivery dates. Interim corrective actions may be useful to quickly address some of the aspects of the Misoperation prior to implementation of a final solution. Examples for interim corrective actions are: disabling a blocking scheme prior to conversion to a permissive scheme, and taking equipment offline or removing equipment from service until new equipment is available.~~

~~The reliability of the BES could be greatly enhanced by making it immune to faults. Protection Systems are applied to the BES to clear faults and contain their negative impacts, thereby maintaining the reliability and stability of the BES. However, it is impossible (or at least highly impractical) to create failure proof Protection Systems. This is particularly true of Protection Schemes which rely on substation to substation communications for proper operation. The communication equipment can be spread over large distances, and be exposed to failure causes beyond the capability of the Protection System's owner's capability to control. Part of proper application of these Protection Systems involves analysis of their behavior during communication failures.~~

~~Where studies have determined that high speed clearing is required over 100% of the protected element to maintain stability, a communication failure must not prevent high speed fault clearing. In general, this will result in some amount of tripping for external faults. That, by definition, is a misoperation. There are usually things that can be done to reduce the tendency to misoperate, and to reduce the impact of a misoperation. However, the possibility typically cannot be eliminated. Altering the Protection System to eliminate tripping for every possible over trip during communication failures would prevent this type of misoperation, but it would negatively impact the stability of the BES.~~

~~Where studies have determined that excessive tripping is a greater threat to stability than slow tripping for a remote end line fault, permissive schemes can be used to provide high speed tripping. These schemes provide security against excessive tripping during communication failures, but will result in slower tripping for some faults. Under the proposed Misoperation definition, this may not always be considered a Misoperation, but it is certainly less than optimal Protection System performance. It does promote system stability however. Improving the likelihood of high speed clearing at the expense of security in these cases, will negatively impact the stability of the BES.~~

~~In rare cases such as the one described above, where altering a Protection System to avoid the recurrence of a Misoperation may lower the reliability or performance of the BES, a declaration addressing the lack of a CAP is required. Additionally, if analysis of the event shows that the cause of the failure is beyond the Protection System owner's ability to prevent or correct (such as a communication failure caused by an external dig in), corrective action may not be appropriate.~~

~~**Part 1.3 Bullet 2** allows for this situation by requiring that where corrective action is not taken, the Protection System owner has to provide a declaration that includes a description of the failure mode, the Misoperation, and the potential impacts on the BES of eliminating the mode of Misoperation.~~

~~While many things can be done to improve the performance of Protection Systems, it is not possible to prevent all failures. Protection Systems which are designed to operate during partial failure modes in a manner that promotes the maintenance of BES stability may experience Misoperations for which a Corrective Action Plan may not be appropriate.~~

~~In some cases, analysis of all available information will not identify a root cause. **Part 1.4** is intended to allow entities to deal with these scenarios and still meet the overall objectives of the reliability standard.~~

~~In some of these cases additional steps may be identified (such as applying more monitoring equipment) to aid in future investigations of subsequent Misoperations. Modifications to the Protection System may be identified which could reduce the likelihood of a recurrence of the Misoperations. These steps and modifications should be identified to aid in future investigations of recurring Misoperations.~~

~~When a root cause is not identified and all investigative avenues have been exhausted, a declaration detailing the description of the investigative work conducted as well as the justification for the decision to conclude the investigation is required.~~

~~**Parts 1.3 and 1.4** both give 120 calendar days from the date of the Misoperation to develop a plan or otherwise address the Misoperation. This give an additional 30 days beyond the deadline established on **Part 1.2.** As discussed above, this allowance provides sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes. Also as discussed above, some regions may choose to implement more stringent deadlines for some of all of its Protection Systems.~~

Requirement 2

If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP, or to prepare a declaration justifying the lack of a CAP.

Where there are multiple Protection System owners involved in a Misoperation, the one or more owners whose Protection System component(s) contributed to the Misoperation will create a CAP or declaration as required by Requirement 2. Owners whose Protection System components operated correctly do not need to create a CAP. All owners should update their investigation documentation to indicate which party or parties are performing a CAP to address the Misoperation.

Resolving Misoperations benefits the Protection System owner and the BES by improving reliability and security. The CAP is an established tool for resolving operational problems. The

NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".

Protection System owners are expected to exercise due diligence in the development and implementation of a CAP. Typically included would be any corrective actions taken to prevent recurrence (along with the date performed), and any corrective actions planned to be taken to prevent recurrence (along with the planned date).

An example of a CAP for a Misoperation determined to have been caused by a failed relay that has not been repaired might be: "Temporarily removed failed relay from service on xx/xx/xx. Plan to repair then return relay to service on xx/xx/xx."

An example of a CAP for a Misoperation determined to have been caused by a failed relay that has been repaired might be: "Temporarily removed failed relay from service on xx/xx/xx. Repaired then returned relay to service on xx/xx/xx."

An example of a CAP for a Misoperation suspected to have been caused by an intermittent relay failure might be: "Temporarily removed suspect relay from service on xx/xx/xx. Replaced with like kind, and placed in service on xx/xx/xx."

If the Misoperation cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners are required to make a declaration to this effect. A "no CAP declaration" would typically include the Misoperation cause and justification for taking no corrective action.

An example of a "no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is expected to be used sparingly.

CAPs should include an evaluation as to whether the entity's Protection Systems at other locations are also vulnerable to the same type of Misoperation.

Requirement 3

If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).

At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.

An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."

An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."

An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review by xx/xx/xx."

If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this effect. A "no action plan declaration" would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.

An example of a "no action plan declaration" might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."

Requirement R4

Finally, the goal of the standard has not been met unless CAP(s) or action plans are actually implemented, as is required in ~~**Part 1.5.**~~Requirement R4. The responsible entity is required to implement and complete a CAP or ~~other~~ action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. ~~The CAP or action plan is intended to correct the root causes of Protection System Misoperations and prevent them from recurring.~~ The responsible entity is also required to complete the CAP or action plan, document the ~~manner in which the plan was implemented~~plan implementation, and retain the appropriate evidence to demonstrate implementation~~.~~ and completion.

The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement 2. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.

Reporting:

A review of the Transmission Availability Data System (TADS) data for the ~~past three~~ years ~~reveals~~2008 – 2010 revealed that the fourth ranked initiating cause of BES outages not related to weather ~~is~~was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.

Section C-1.4 requires periodic data reporting and references a common reporting format to facilitate consistent reporting of Misoperation data by all Transmission Owners, Generator Owners, and Distribution Providers. Reporting Misoperation data in a common format permits the ERO to analyze the data, develop meaningful metrics for measuring Protection System performance, identify trends in Protection System performance that negatively impact reliability, and identify lessons learned.

Analysis of data from all Misoperations across North America makes possible identification of issues and trends that may not be identifiable through analysis of smaller data sets on an entity or regional basis. Information regarding identified issues and trends and recommended actions will be shared with Transmission Owners, Generator Owners, and Distribution Providers through lessons learned or industry alerts. Sharing this information will permit recipients to take appropriate actions to drive improvements in Protection System performance.

The common reporting template also will improve the usefulness of metrics developed to track Protection System performance. While the most relevant category defined in TADS is titled "Failed Protection System Equipment," the title is not an accurate description of the information reported in the metric. This metric includes all Protection System Misoperations that are not related to human error, which is only a subset of all Protection System Misoperations. The Protection System Misoperations related to human error (e.g., miscoordinated settings, incorrect setting calculations, and errors in applying settings to the relay, etc.) are tracked separately from Protection System equipment-related Misoperations, and are grouped together with other human errors by a utility employee or contractor. Similarly, Protection System Misoperations related to failed equipment such as a failed CVT on the primary insulation side are reported under "Failed AC Substation Equipment." Reporting of Misoperations data using the common format specified in C-1.4 will permit development of metrics specific to Protection System Misoperations, with the potential to break down the metric by category of Misoperation (e.g., failure to trip, slow trip, unnecessary trip, etc.) and cause of Misoperation (ac system, dc system, as-left personnel error, incorrect setting/logic/design, and relay failures/malfunctions).

Reporting Misoperations and their CAPs or action plans provides a means of monitoring and assessing Misoperations. Reviewing and tracking this information provides a method of validating the actions taken to address the causes of Misoperations. A second need for reporting Misoperations is to facilitate the identification of trends in Protection System performance that negatively impact reliability. Analyzing data from all Misoperations across North America will make it possible to identify trends that may not be discernible through analysis of smaller data sets on an entity or regional basis.

Misoperations and updates will be submitted to the Regional Entity on a quarterly basis per the following schedule:

Reporting Quarter	**Submission Date**
1st Quarter (Jan 1 – March 31)	May 31
2nd Quarter (Apr 1 – June 30)	August 31
3rd Quarter (July 1 – Sept 30)	November 30
4th Quarter (Oct 1 – Dec 31)	February 28

The two calendar months reporting of Misoperations that occurred within the quarterly reporting period corresponds to the recommendations provided by ERO-RAPA and also correlates to the time which the majority of Regional Entities were using in 2011. It is believed that two calendar months is a reasonable time for an entity to submit their Misoperations data after the close of a reporting period. Reporting and updating on a limited time interval and lag (from occurrence) aids in focusing on high trend items of common mode failures. A longer period of time for reporting could prevent high trend failures from being quickly recognized.

Examples of reporting:

1. If a Misoperation occurred on March 30 but was not identified as a Misoperation until June 2, then this Misoperation would be reported in the second quarter reporting period.
2. If the Misoperation in example 1 was not completely investigated in the second quarter but a cause was determined on July 2, then a resubmittal should be reported in the third quarter.
3. If the Misoperation in examples 1 and 2 had its CAP completed on November 2, then a resubmittal indicating that the CAP was completed should be reported in the fourth quarter.

Implementation Plan

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standards drafting team proposes modifying the following approved definition:

Misoperation: Any of the following:

1. **Failure to Trip - During Fault -** A failure of a Protection System to operate for a Fault within the zone it is designed to protect. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

2. **Failure to Trip - Other Than Fault -** A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

3. **Slow Trip - During Fault -** A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault Clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)

4. **Slow Trip - Other Than Fault -** A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault -** A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.

6. **Unnecessary Trip - Other Than Fault -** A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, construction or commissioning activities.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

General Considerations

PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for Facilities that are part of the BES.

Facilities not included

- Special Protection Systems (SPS) or Remedial Action Schemes (RAS)
- Undervoltage Load Shedding (UVLS)

Relay functions not included (these are non-protective functions that may be imbedded within a Protection System)

- Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)

- Automation (e.g. data collection)

Effective Date of New or Revised Standards and Definitions

First day of the first calendar quarter that is six months beyond the date that PRC-004-3 is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The proposed definition of Misoperation shall become effective on the same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.

Implementation Plan for Requirements R1, R2, R3 and R4

Entities shall be 100% compliant on the first day of the first calendar quarter six months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter six months following Board of Trustees adoption.

Retirement of Existing Standards

The existing standards PRC-003-1 and PRC-004-2a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3.

Implementation Plan ~~for PRC-004-03~~

~~**Standards Involved:**~~

- ~~Approval:~~

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements~~:~~

- PRC-003-1~~ – ~~ – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection ~~Systems~~System
- PRC-004-~~1a – ~~2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations
  - ~~PRC-004-2 – Analysis and Mitigation of Transmission and Generation Protection System Misoperations~~
- ~~Related~~

~~PRC-003-STD-1, PRC-004-WECC-1: These are two regional standards~~

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standards drafting team proposes modifying the following approved definition:

Misoperation: Any of the following:

1. **Failure to Trip - During Fault -** A failure of a Protection System to operate for a Fault within the zone it is designed to protect. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

2. **Failure to Trip - Other Than Fault -** A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. (The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.)

3. **Slow Trip - During Fault -** A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault Clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)

4. **Slow Trip - Other Than Fault -** A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault -** A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.

6. **Unnecessary Trip - Other Than Fault -** A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, construction or commissioning activities.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

General Considerations

PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where ~~those standards will overlap~~PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard~~. Doing so will ensure compliance with the less stringent standard as well. There are no apparent conflicts between the standards that would lead to mutually exclusive compliance~~.

~~**Prerequisite Approvals:**~~
~~The proposed standard is **not** dependent on any prerequisite approvals.~~

~~**Revision to Sections of Approved Standards and Definitions:**~~
~~There is one revised definition for the proposed standard:~~

~~***Misoperation:*** *Any of the following:*~~

1. ~~**Failure to Trip - During Fault** - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect.~~
2. ~~**Failure to Trip - Other Than Fault** - Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.~~
3. ~~**Slow Trip** - Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect.~~
4. ~~**Unnecessary Trip - During Fault** - Any Protection System operation for a Fault not within the zone it is designed to protect.~~
5. ~~**Unnecessary Trip - Other Than Fault** - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.~~

~~Retirement of Existing Standards:~~

~~The existing Standards PRC-003-1, PRC-004-1a, and PRC-004-2 shall be retired upon regulatory approval of PRC-004-3.~~

~~PRC-003-1 is currently not enforceable, but requires the establishment of a procedure by the RRO. The new PRC-004-3 puts this obligation on the Functional Entities instead, and specifies the minimum elements required in the procedure, making PRC-003-1 unnecessary and duplicative.~~

~~PRC-004-1a and -2 Requirements R1 and R2 require the Functional Entities implement the procedures specified in PRC-003-1. R1 in the new PRC-004-3 includes this obligation. R3 in PRC-004-1A and -2 requires reporting to the RRO, which has now been included in the Compliance section of the standard. Together, these elements make PRC-004-1A and -2 superfluous as well.~~

Applicability~~:~~

This standard applies to the following functional entities:

- Transmission ~~Owners~~Owner
- Generator ~~Owners~~Owner
- Distribution ~~Providers~~Provider

This standard applies to the following Facilities:

- Protection Systems for Facilities that are part of the BES.

Facilities not included

- Special Protection Systems (SPS~~),~~) or Remedial Action Schemes (RAS~~), and Under Voltage~~)
- Undervoltage Load Shedding ~~programs~~(UVLS)

Relay functions not included (these are ~~*excluded from this standard.*~~non-protective functions that may be imbedded within a Protection System)

- Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)
- Automation (e.g. data collection)

Effective Date~~:~~

~~The effective date is the date entities are expected to meet the performance identified in this standard.~~

~~Requirement R1~~ **of New or Revised Standards and** ~~its associated parts shall become effective on the~~

Definitions

First day of the first calendar quarter that is six months beyond the date that PRC-004-3 is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter~~, 3~~ that is six months ~~after~~beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The proposed definition of Misoperation shall become effective on the same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.

Implementation Plan for Requirements R1, R2, R3 and R4

Entities shall be 100% compliant on the first day of the first calendar quarter six months following applicable regulatory ~~***approval. In***~~approvals, or in those jurisdictions where no regulatory approval is required, ~~***all requirements go into effect***~~ on the first day of the first calendar quarter~~***, 3***~~ six months ~~***after***~~following Board of Trustees adoption.

Retirement of Existing Standards

~~Because the standard does not deviate significantly from what is required today, it is believed that this standard can be implemented on a relatively short schedule.~~

The existing standards PRC-003-1 and PRC-004-2a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3.

Project 2010-05.1 Protection System Misoperations

Please **DO NOT** use this form. Please use the electronic comment form at the link below to submit comments on the second draft of the PRC-004-3 standard for Protection System Misoperations. Comments must be submitted by **September 7, 2012.** If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Background Information:

The initial draft of this standard and associated documents were posted for a 30-day formal comment period from June 10, 2011 through July 11, 2011. Stakeholders from 106 companies representing all 10 Industry Segments provided feedback. The Protection System Misoperation Standard Drafting Team (PSM SDT) has responded to all commenters and developed a second draft of the standard for Protection System Misoperation Identification and Correction based on stakeholder input. Changes to the standard include:

- Revisions to the definition of Protection System Misoperation.
- Revisions to the Applicability section to include exclusions for relay functions.
- Separating Requirement R1 into four requirements.
- Introducing time intervals and activities in Requirements R1, R2, and R3 associated with identifying, investigating, and addressing Misoperations.
- Addressing Misoperations when two or more entities own separate components in a Protection System.
- Modifying the VRFs and VSLs to reflect the changes listed above.
- Modifying the Guidelines and Technical Basis section to include more explanation and examples for the definition of Misoperation and the requirements.

Please read and review the standard and the Consideration of Comments document carefully before answering the following questions. The '**Guidelines and Technical Basis**' section (pp 15-22) of the standard provides examples and discussion around the technical merits and intent of the requirements, measures, and definition(s), etc. Also, the drafting team's responses to stakeholder's comments and the subsequent changes made to the standard are explained in detail in the **Consideration of Comments** document. A thorough read and review of these documents may eliminate the need for additional comments thereby reducing workload for both the commenters and the drafting team. The PSM SDT is posting this standard for a formal 45-day comment period and successive ballot. The drafting team thanks you in advance for your constructive thoughts.

For questions 1-8, please provide specific comments related to the individual question. Please reserve question 9 for general comments not related to questions 1-9.

1. The definition of "Misoperation" has been revised from the initial posting. Do you agree with the revised definition? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No

   Comments:

2. Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, and designate each Misoperation. Do you agree with this approach? If you do not agree, please provide specific alternatives.

   ☐ Yes
   ☐ No

   Comments:

3. Requirements R1, R2, and R3 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with these time limits? If not, please provide specific reasons why not and alternative recommendations.

   ☐ Yes
   ☐ No

   Comments:

4. The team has modified the standard to address Misoperations when two or more entities own separate components in a Protection System. Do you agree that the standard adequately deals with this situation? If not, please provide specific reasons why not and alternative recommendations.

☐ Yes

☐ No

Comments:

5. Attachment 1 lists and describes the data to be included in the quarterly reporting. Do you believe this data is appropriate for metric analysis? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

6. The team has included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific reasons why not and alternative recommendations and justifications.

☐ Yes

☐ No

Comments:

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

☐ Yes

☐ No

Comments:

8. The team has included an Implementation Plan with this posting. Do you agree with the changes? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

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

   Comments:

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2010-05.1 Protection Systems: Phase 1(Misoperations) Mapping Document

Mapping Document Showing Translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, and PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into PRC-004-3 — Protection System Misoperation Identification and Correction.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
	RRO procedures.	
R1. Part 1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	PRC-004-3 Applicability Section 4.2 Facilities.	**4.2.** Facilities **4.2.1** Protection Systems for Facilities that are part of the BES **4.2.2** Facilities not included **4.2.2.1** Special Protection Systems (SPS) or Remedial Action Schemes (RAS) **4.2.2.2** Undervoltage Load Shedding (UVLS) **4.2.3** Relay functions not included (these are non-protective functions that may be imbedded within a Protection System) **4.2.3.1** Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples) **4.2.3.2** Automation (e.g. data collection)
R1. Part 1.2. Data reporting requirements (periodicity and format) for Misoperations.	PRC-004-3 Compliance Section C 1.4 Additional	**C. 1.4. Additional Compliance Information** Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
	Compliance Information	will submit the data identified in PRC-004 - Attachment 1 to the CEA within two calendar months following the end of each calendar quarter. The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.
R1. Part 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Identify and review each Protection System operation. If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information. **1.2** Designate each Misoperation (if any). **1.3** Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified. **R2.** Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner,

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		Generator Owner, or Distribution Provider shall: o Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or o Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** For each Misoperation without an identified cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete: o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or o A declaration explaining why no further actions will be taken.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		R4. For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider shall: **4.1** Implement the CAP or action plan **4.2** Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion
R1. Part 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. The standards development process mandates the standards be reviewed once every five years. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider See **PRC-004-3**
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
	Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1.3** Distribution Provider See **PRC-004-3**

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Identify and review each Protection System operation. If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information. **1.2** Designate each Misoperation (if any). **1.3** Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified. **R2.** Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall: o Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		locations, or o Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** For each Misoperation without an identified cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete: o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or o A declaration explaining why no further actions will be taken. **R4.** For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider shall: **4.1** Implement the CAP or action plan **4.2** Maintain detailed implementation records of

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		each CAP or action plan including dated information surrounding any revision(s) and completion
R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Identify and review each Protection System operation. If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information. **1.2** Designate each Misoperation (if any). **1.3** Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified. **R2.** Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall: o Develop a Corrective Action Plan (CAP) for the

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or o Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** For each Misoperation without an identified cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete: o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or o A declaration explaining why no further actions will be taken. **R4.** For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		shall: **4.1** Implement the CAP or action plan **4.2** Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	PRC-004-3 Requirement 4 Compliance Section C 1.4 Additional Compliance Information	**R4.** For each CAP or action plan, the Transmission Owner, Generator Owner, or Distribution Provider shall: **4.1** Implement the CAP or action plan **4.2** Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion **C. 1.4. Additional Compliance Information** Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA within two calendar months following the end of each calendar quarter.

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.

A. Introduction

1. **Title:** **Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**

2. **Number:** PRC-003-1

3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

 4.1. Regional Reliability Organization

5. **Effective Date:** May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:

 R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).

 R1.2. Data reporting requirements (periodicity and format) for Misoperations.

 R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.

 R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.

R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.

M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.

M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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.	01/20/06

A. Introduction

1. **Title:** **Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-1a

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **Effective Date:** To be determined

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1.a	February 17, 2011	3. Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1.a	February 17, 2011	Adopted by the Board of Trustees	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

Project 2010-05.1 – PRC-004-3: Protection System Misoperations

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

PRC-004-3 has four (4) requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. The revised standard requires entities to identify and review Protection System operations and designate each Misoperation; then investigate each Misoperation and document the findings. If a cause is identified, the entity either creates a Corrective Action Plan (CAP) or writes a declaration that they cannot correct the misoperating device(s). If a cause is not identified, the entity either creates an action plan for additional investigation or a writes a declaration that no further work will be done. The next step is to implement and complete the CAP or action plan. If the action plan leads to the determination of a cause, then the entity would either create a Corrective Action Plan (CAP) or write a declaration. The requirements recognize and encompass the possibility that components of a Protection System can be owned by different entities.

The requirements of PRC-004-3 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-WECC-1, EOP-008-1, PRC-004-2a and of TPL-001-2 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1, R2 and R3 are assigned a VRF of Medium, while Requirement R4 is assigned a VRF of High.

PRC-004-3 Requirements R1, R2 and R3 are related to identifying Protection System operations, designating Misoperations, investigating Misoperations and developing Corrective Action Plans (CAP) or action plans. The SDT determined that the assignment of a VRF of Medium was consistent with the NERC criterion that states "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…"

PRC-004-3 Requirement R4 relates to implementing and completing CAPs or action plans. The SDT determined that the assignment of a VRF of High was consistent with the NERC criterion that states "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…"

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has assigned a Medium VRF which is consistent with EOP-008-1 Requirement R8 (which is similar in nature to PRC-004-3 Requirement R1.)
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.

VRF and VSL Justifications – PRC-004-3, R1			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 120 calendar days but less than or equal to 130 calendar days of the operation's occurrence. OR The responsible entity identified a Protection System operation that operated one of its interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System Operation that operated one of its interrupting devices in 120 calendar days and determined	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 130 calendar days but less than or equal to 140 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 140 calendar days but less than or equal to 150 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 – 1.3 in more than 150 calendar days of the operation's occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its interrupting devices in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2.

VRF and VSL Justifications – PRC-004-3, R1			
the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.3.			OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.3. OR The responsible entity completed its investigation of a Protection System Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's Protection System component contributed to the Misoperation, and failed to notify and provide requested investigative information to that entity in accordance with Requirement R1, Part 1.1.

VRF and VSL Justifications – PRC-004-3, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to

VRF and VSL Justifications – PRC-004-3, R2			
	bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the completion of the investigation or receiving notification.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the completion of the investigation or receiving notification. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.

VRF and VSL Justifications – PRC-004-3, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely

VRF and VSL Justifications – PRC-004-3, R3			
	to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to 190 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 190 calendar days but less than or equal to 200 calendar days following the associated interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 200 calendar days but less than or equal to 210 calendar days following the completion of the investigation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than 210 calendar days following the completion of the investigation. OR The responsible entity failed to develop, implement, and documented an action plan, or a declaration in accordance with Requirement R3.

VRF and VSL Justifications – PRC-004-3, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion 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 Parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is consistent with PRC-004-2a, Requirements R1 and R2, PRC-004-WECC-1 Requirement R2.1, and TPL-001-2 Requirement R2 Part 2.7 which have approved VRFs of High.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion for a High VRF.

<table>
<tr><th colspan="4">VRF and VSL Justifications – PRC-004-3, R4</th></tr>
<tr><td>FERC VRF G5 Discussion</td><td colspan="3">Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:
This requirement does contain obligations that are administrative in nature but they support the high risk reliability objective; the assigned VRF of High is appropriate for the requirement.</td></tr>
<tr><td colspan="4">Proposed VSL</td></tr>
<tr><td>Lower</td><td>Moderate</td><td>High</td><td>Severe</td></tr>
<tr><td>The responsible entity maintained records of a CAP or action plan but the records were incomplete.</td><td></td><td></td><td>The responsible entity failed to implement a CAP or action plan.
OR
The responsible entity failed to maintain records of a CAP or action plan.</td></tr>
</table>

VRF and VSL Justifications – PRC-004-3, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSLs for incomplete documentation and a binary aspect for failure to implement.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the previous severity level and does not lower the current level of compliance for the similar Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, R4	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Ballot Pools Forming:	July 25 – August 27, 2012
Formal Comment Period Open:	July 25 – September 7, 2012

Upcoming Ballots:

Initial Ballot and Non-Binding Poll:	August 29 – September 7, 2012

Now Available

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is open through 8 p.m. Eastern on Friday, September 7, 2012. Two ballot pools, one for the standard and one for the associated VRFs and VSLs, are open through **8 a.m. Eastern on Monday, August 27, 2012.**

Instructions for Joining Ballot Pool(s)

Two ballot pools are being formed. Registered Ballot Body members must join the first ballot pool to be eligible to vote in balloting of standard PRC-004-3, and a second, separate ballot pool to be eligible to cast an opinion in the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join each of these ballot pools at the following page: Join Ballot Pool

Note that there is no requirement to join both of these ballot pools; Registered Ballot Body members who are only interested in voting during the ballot of the standard are not required to join the ballot pool for the non-binding poll, and vice versa.

During the pre-ballot windows, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The ballot pool list servers for these ballot pools are:

Initial ballot: bp-2010-05.1_PRC-004-3_in@nerc.com
Non-binding poll: bp-2010-05.1_PRC-004_NB_in@nerc.com

The ballot pools are open **through 8 a.m. Eastern on Monday, August 27, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, September 7, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information on the electronic survey, and are not required to answer any other questions.

Next Steps

An initial ballot of the standard and non-binding poll of the associated VRF/VSLs will be conducted beginning on Wednesday, August 29, 2012 through 8 p.m. Eastern on Friday, September 7, 2012.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Ballot Pools Forming:	July 25 – August 27, 2012
Formal Comment Period Open:	July 25 – September 7, 2012

Upcoming Ballots:

Initial Ballot and Non-Binding Poll:	August 29 – September 7, 2012

Now Available

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is open through 8 p.m. Eastern on Friday, September 7, 2012. Two ballot pools, one for the standard and one for the associated VRFs and VSLs, are open through **8 a.m. Eastern on Monday, August 27, 2012.**

Instructions for Joining Ballot Pool(s)

Two ballot pools are being formed. Registered Ballot Body members must join the first ballot pool to be eligible to vote in balloting of standard PRC-004-3, and a second, separate ballot pool to be eligible to cast an opinion in the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join each of these ballot pools at the following page: Join Ballot Pool

Note that there is no requirement to join both of these ballot pools; Registered Ballot Body members who are only interested in voting during the ballot of the standard are not required to join the ballot pool for the non-binding poll, and vice versa.

During the pre-ballot windows, members of the ballot pools may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The ballot pool list servers for these ballot pools are:

Initial ballot: bp-2010-05.1_PRC-004-3_in@nerc.com
Non-binding poll: bp-2010-05.1_PRC-004_NB_in@nerc.com

The ballot pools are open **through 8 a.m. Eastern on Monday, August 27, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, September 7, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot *may no longer enter comments on the balloting screen*, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information on the electronic survey, and are not required to answer any other questions.

Next Steps

An initial ballot of the standard and non-binding poll of the associated VRF/VSLs will be conducted beginning on Wednesday, August 29, 2012 through 8 p.m. Eastern on Friday, September 7, 2012.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot for **PRC-004-3 – Protection System Misoperation Identification and Correction** and a non-binding poll of the associated VRF/VSLs concluded on Friday, September 7, 2012.

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Approval	Non-binding Poll Results
Quorum: 86.71%	Quorum: 84.17 %
Approval: 37.68%	Supportive Opinions: 37.36 %

Next Steps

The drafting team will consider all comments received during the formal comment and ballot period and, if needed, make revisions to the standard. If significant changes are made, the drafting team will submit the standard for quality review prior to posting for a successive ballot.

Background

PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; as a key Element for BES reliability is the correct performance of Protection Systems. PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The [Standards Processes Manual] contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Ballot Results	
Ballot Name:	Project 2010-05.1 PRC-004-3 Initial Ballot July 2012_in
Ballot Period:	8/29/2012 - 9/7/2012
Ballot Type:	Initial
Total # Votes:	372
Total Ballot Pool:	429
Quorum:	**86.71 % The Quorum has been reached**
Weighted Segment Vote:	37.68 %
Ballot Results:	**The drafting team will review the comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	113	1	33	0.363	58	0.637	5	17
2 - Segment 2.	9	0.7	3	0.3	4	0.4	1	1
3 - Segment 3.	107	1	30	0.33	61	0.67	4	12
4 - Segment 4.	33	1	8	0.276	21	0.724	0	4
5 - Segment 5.	93	1	20	0.282	51	0.718	10	12
6 - Segment 6.	54	1	12	0.286	30	0.714	3	9
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	11	0.8	5	0.5	3	0.3	1	2
9 - Segment 9.	2	0	0	0	0	0	2	0
10 - Segment 10.	7	0.5	3	0.3	2	0.2	2	0
Totals	**429**	**7**	**114**	**2.637**	**230**	**4.363**	**28**	**57**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Negative	
1	Avista Corp.	Scott J Kinney		

1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan	Negative	
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Negative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil		
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Grand River Dam Authority	James M Stafford	Negative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour		
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	

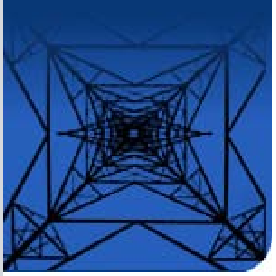
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	
1	Portland General Electric Co.	John T Walker	Negative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Negative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Trans Bay Cable LLC	Steven Powell	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy	Negative	
3	Blue Ridge Electric	James L Layton	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	

3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott	Affirmative	
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Negative	
3	Clearwater Power Co.	Dave Hagen	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Consumers Power Inc.	Roman Gillen	Negative	
3	Coos-Curry Electric Cooperative, Inc	Roger Meader	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	Fall River Rural Electric Cooperative	Bryan Case	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw	Negative	
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Negative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Negative	
3	Old Dominion Electric Coop.	Bill Watson	Abstain	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall	Negative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	
3	Platte River Power Authority	Terry L Baker	Affirmative	

3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Raft River Rural Electric Cooperative	Heber Carpenter	Negative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Turlock Irrigation District	James Ramos	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Negative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	

5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Bridgeport Energy	Cleyton Tewksbury		
5	Caithness Long Island, LLC	Jason M Moore	Abstain	
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Negative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Negative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Negative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	El Paso Electric Company	David Hawkins	Negative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero	Abstain	
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Negative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	MidAmerican Energy Co.	Neil D Hammer	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Chelan County	John Yale	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	

5	Salt River Project	William Alkema		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	Turlock Irrigation District	Marty Rojas	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs		
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	
6	Duke Energy	Greg Cecil	Negative	
6	El Paso Electric Company	Tony Soto	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	Progress Energy	John T Sturgeon	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		



6	Southern California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Turlock Irrigation District	Amy Petersen	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons		
8		Merle Ashton		
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Abstain	
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Legal and Privacy

404.446.2560 voice : 404.446.2595 fax

Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326

Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-binding Poll Results

Project 2010-05.1

Ballot Results	
Non-binding Poll Name:	Project 2010-05.1 Non-binding Poll
Poll Period:	8/29/2012 - 9/7/2012
Total # Opinions:	335
Total Ballot Pool:	398
Summary Results:	84.17% of those who registered to participate provided an opinion or an abstention; 37.36% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	
1	City of Tallahassee	Daniel S Langston		
1	City Utilities of Springfield, Missouri	Jeff Knottek	Negative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan	Negative	

NERC

1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Negative	
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Negative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil		
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	
1	Grand River Dam Authority	James M Stafford	Negative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour		
1	Minnkota Power Coop. Inc.	Daniel L Inman	Negative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	

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1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Denike		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		

2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy	Negative	
3	Blue Ridge Electric	James L Layton	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott	Abstain	
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Negative	
3	Clearwater Power Co.	Dave Hagen	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan		
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Negative	
3	Consumers Power Inc.	Roman Gillen	Negative	
3	Coos-Curry Electric Cooperative, Inc	Roger Meader	Negative	
3	Cowlitz County PUD	Russell A Noble		
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Negative	
3	Entergy	Joel T Plessinger	Abstain	
3	Fall River Rural Electric Cooperative	Bryan Case	Negative	
3	FirstEnergy Energy Delivery	Stephan Kern	Negative	
3	Flathead Electric Cooperative	John M Goroski	Negative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	

NERC

3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw	Negative	
3	Lincoln Electric System	Jason Fortik	Negative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Negative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall	Negative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Raft River Rural Electric Cooperative	Heber Carpenter	Negative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Negative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen		
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens		

3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	
3	Umatilla Electric Cooperative	Steve Eldrige	Negative	
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Negative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Negative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Negative	

5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Bridgeport Energy	Cleyton Tewksbury		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb		
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex		
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Negative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer	Affirmative	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	
5	Florida Municipal Power Agency	David Schumann	Negative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Negative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Negative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	

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5	MidAmerican Energy Co.	Neil D Hammer	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Negative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Negative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs		

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6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Negative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Negative	
6	Luminant Energy	Brad Jones	Negative	
6	Manitoba Hydro	Daniel Prowse	Negative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	Progress Energy	John T Sturgeon	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet		
6	Santee Cooper	Michael Brown	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		
6	Southern California Edison Company	Lujuanna Medina	Negative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran		

8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Name (63 Responses)
Organization (63 Responses)
Group Name (32 Responses)
Lead Contact (32 Responses)
Contact Organization (32 Responses)
Question 1 (17 Responses)
Comments (95 Responses)
Question 1 (75 Responses)
Question 1 Comments (78 Responses)
Question 2 (74 Responses)
Question 2 Comments (78 Responses)
Question 3 (74 Responses)
Question 3 Comments (78 Responses)
Question 4 (67 Responses)
Question 4 Comments (78 Responses)
Question 5 (69 Responses)
Question 5 Comments (78 Responses)
Question 6 (67 Responses)
Question 6 Comments (78 Responses)
Question 7 (64 Responses)
Question 7 Comments (78 Responses)
Question 8 (62 Responses)
Question 8 Comments (78 Responses)
Question 9 (0 Responses)
Question 9 Comments (78 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
No
Requirement R1 (as well as the other Requirements in the Standard) should be formatted to start with “Each…”. For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do. The use of the words “in its Facility” should be changed to reflect what is being protected. Suggested wording for consideration: R1. Each Transmission Owner, Generator Owner, and Distribution Provider within 120 calendar days of a Protection System Misoperation initiating an interrupting device operation in its system shall have and implement a procedure to identify and address all Protection System Misoperations within its system. Closure is also needed in the procedure to ensure a definitive corrective response to a misoperation to prevent its recurrence.
No
As with R1, Requirements R2 and R3 should be formatted to start with “Each...”. For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do. The time limits specified are excessive for plans that do not include correcting the problem. Correction of Misoperations is extremely important to reliability because the Misoperation may indicate a defect that could have significant consequences. The time limit for R1 should be 15 calendar days, an additional 15 calendar days for R2, and 15 days for R3. A definite completion time period for correcting the Misoperation should also be specified. Sixty days would not be an excessive time assuming outages may be needed, hardware ordered, etc. to prevent a recurrence.
Yes

No
An additional field should be added to improve the metric analysis of microprocessor relay malfunctions. For example, the field value for a microprocessor relay malfunction could include the following: Setting Error-Incorrect Numerical Input Specified Setting Error-Incorrect User-Programmed Custom Logic Incorrect Design-Incorrect User Application Incorrect Design-Wiring Firmware Version Mismatch by User Others
No
There should be no respopnse to this question. I can't deselect either "Yes" or "No".
Yes
Yes
Measurement M1 has that "Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of dated investigation report or documented findings for each Misoperation." This provides a choice in a document type with either a formal report or other method of documenting the findings. On page 22 of 28 of PRC-004-3, in the Application Guidelines section, it states "An investigation report may include...” which dictates the use of an investigation report, and eliminates the choice between a formal report or other method of documenting findings as stated in M1. The Application Guidelines should be consistent with the standard portion of the document. There is a typographical error on the first bulleted item on page 6 of the standard. This item should read: Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).
Group
SPCWG
Heidt Melson
SPP
Agree
Individual
Dale Dunckel
Okanogan PUD
Yes
Yes
Yes
Yes
Yes
No
In the VSL for R4 this is listed as a High Severity. We feel that small entities which are on a 6 year audit cycle could have issues with document retention. Small entities 6 year entities do not have the resources to have the backup systems that larger entities. Also 6 year entities do not have the space and budget to ensure all documents are retained.
No
As stated in Questin 6, we feel that a 6 year data retention policy could prove onerous to small entities. We would prefer a much smaller data retention policy, such as 3 years (which would be the retetion period of large entities.

Yes
Group
Southwest Power Pool Regional Entity
Emily Pennel
Southwest Power Pool Regional Entity
Yes
Yes
Yes
With the proposed time limits, NERC may have to clarify how and when entities submit to the RE database misoperations that are still under investigation.
No
If Owner A notifies Owner B that Owner B’s component contributed to a misoperation, after being notified, Owner B should be responsible for performing misoperations analysis and reporting. The way the standard reads, there is no responbility for Owner B to investigate a component that didn’t operate but did contribute to a misoperation.
Yes
Yes
Yes
In Section C 1.2, the following sentence does not seem to make sense because there are no shorter time periods specified: “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.”
Yes
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Agree
NPCC
Individual
Michael Jones
National Grid
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Individual
Michael Moltane
ITC
No
For 1 through 3, The definitions should be revised to remove the need for the clarifications in parenthesis. One such revision should include clarifying the scope of a ‘Protection System.’ It is not clear whether multiple protection schemes for a single element would be considered one ‘Protection System’ or if each scheme is considered a ‘Protection System’. It may require clarifying the definition of ‘Protection System’ within NERC Glossary or addressing directly in this standard. What is the definition of ‘slow?’ Is it only defined by TPL standards or expected operation time designed into the ‘Protection System?’
No
Requirement R1 states that all operations need to be identified and reviewed. This requirement should clarified to exempt out-of-service equipment.
No
R1, 120 calendar days may not be enough time for those instances when multiple outages occur during large storms such as hurricanes, tornadoes, etc. This needs to be addressed in R1 and should allow that an extension can be requested for those types of events reported in DOE 417 and EOP 004.
No
It is unclear between R1 and R4 who needs to report the misoperation. R4 should specify the owner of the component that initiated the misoperation as the reporter so that a single misoperation is not reported by multiple entities. In 1.1 once notified, the other entity should be allowed additional time (possibly another 120 days?) to analyze the Protection System operation to determine the component that malfunctioned. As written there is only a single timeframe beginning with the outage. The word ‘necessary’ should be included between ‘any’ and ‘requested’ in R1.1.
No
If an entity is required to report a misoperation due to a malfunction of another entity’s component, then there should be a space for the other Registered Entity’s name.
No
The interval between severity levels should be 30 days instead of 10 days. For the lower severity level associated with R4, the standard of ‘incomplete records’ is subjective unless M4 is revised.
No
M1, M2, M3 seem sufficient. M4 is unclear. Please clarify. The following would be clearer. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include dated electronic or hard copy records that document the implementation, completion and any revision to each CAP or action plan. Acceptable records include, but are not limited to: - Dated work management program records - Dated Work orders - Dated Maintenance Records
Yes
Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the

first or second half of the year. This comment was provided in July 2011, but the response did not explain the reason for quarterly reports. If the SDT feels it should remain, then please provide a technical justification for this decision. Has the “Application Guidelines” been thoroughly reviewed? Why haven’t there been any questions regarding what is in these guidelines? None of the Requirements, Measures or Compliance sections mentions it, so it should be treated only as a reference-guide. R2, first bullet point requires an entity to analyze the applicability of a CAP to other protection systems. This should be removed as it exceeds the scope of this standard.
Group
Western Small Entity Comment Group
Steve Alexanderson
Central Lincoln
No
The comment group is concerned with the use of the phrase “slower than intended” in definition 4. The actual intended speed of operation is/was in the mind of the protection engineer who may not necessarily be available to testify regarding his intent for every fault. Settings documentation generally does not show speed of operation, only set points and manufacturer curves. A speed of operation may be derived from these settings right down to the millisecond, but the protection engineer did likely count on this level of precision after considering CT and relay measurement error and coordinating margin. Lacking a tolerance, the documented settings do not fully show the “intent.” In addition the documentation itself may be in error and possibly be the cause of a misoperation (although not by this definition if we use the document to gage intent). Entities and Compliance Enforcement will need more guidance from the drafting team on just how to measure “slower than intended”, and to understand just how slow that is. In the end, however, it is not the intended speed that matters, it is the result. The parenthetical suggests it is the result that counts, but we don’t see the parenthetical overruling the “slower than intended” language. Slow Trip - During Fault - A slow Protection System operation for a Fault within the zone it is designed to protect, resulting in miscoordination with other Protection Systems or failure to meet the performance requirements of the TPL standards.
No
The comment group does not agree that every operation needs to be reviewed; only those that are clearly misoperations or are suspected to be misoperations should need to be reviewed. Reviewing and documenting the review of proper operations provides no reliability benefit and may cause a detriment to reliability by directing resources away from where they might make a difference.
Yes
Yes
Yes
But we do not like the new format. Having each event on an individual line made the information easier and quicker to find. The new format has each event spread over many rows and columns.
No
Violation risk factors should be entity specific based on the equipment owned and their place in the system and not on the requirement alone.
No
We disagree with M1 for the same reason we disagree with R1 in Q2 above.
Yes
Individual
Terri Pyle
Oklahoma Gas & Electric
Agree

Southwest Power Pool
Individual
paul haase
seattle city light
Yes
No
Seattle City Light (SCL) does not agree with the time limits. SCL agrees that it is important for reliability that Misoperation CAPs be created and implemented within a reasonable time, but does not believe that the reliability benefit that might possibility accrue from meeting staged interim deadlines for analysis and for creating a CAP outweighs the administrative compliance burden created to document that each interim deadline has been met. SCL instead recommends that a single time limit be required for implementing an appropriate CAP following each Misoperation. Furthermore, SCL recommends a somewhat longer period, of either 240 or 365 days, to accommodate seasonal constraints. For SCL, elements associated with a Misoperation occurring in October at the beginning of the winter storm season might, in a heavy winter, not be available for operational analyses and testing until the following March or April, a length of time that could exceed 180 days. Such seasonal constraints are not unique to SCL, but also exist in summer for entities in the southern parts of North America.
Yes
No
I) There are too many classification choices in the “Resolution Status” field of the report form. An equally effective status report can be delivered using three choices: 1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed – Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] II) The form for GOs should differ from that for TOs, for the following reasons: a. GOs are not in a position to respond to the last item on p.1, “Additional BES Interruptions.” We know only what happens in our plants, not repercussions on the grid. b. The “slow trip” entries in the “Misoperations Category” do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker – that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.
No
For R1, R2 and R3, SCL does not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the “Find, Fix, and Track” category or non-zero-defect treatment, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement.
Yes
Yes

While Seattle City Light generally agrees with the concepts presented in the draft Standard and appreicates the effort required to develop and review Standards, SCL finds the reliability improvements promised by the draft to be diluted with unnecessary backwards-looking compliance activities. The draft appears tone-deaf to the changes at NERC regarding purely administrative tasks (e.g., Paragraph 81 effort to remove them, whereas this draft adds several such as R4.2 and the second bullets of R2 and R3). One example is the emphasis on meeting and documenting multiple dates for each Misoperation. Another is a need to document completion of each Misoperation CAP almost as if it were a Mitigation Plan to correct a Self-Reported violation, rather than, for example, relying primarily on the corrective action documentation already reported for GADS and TADS. The draft also would benefit from application of the non-zero-defect concepts introduced with the latest draft of CIP version 5. Changes such as these will minimize the need to revise the Standard yet again to align with present directions.
Individual
Louis C. Guidry
Cleco Corporation
No
Need clarification on what is meant by referencing the TPL performance standards in section 3.
No
Please add some example(s) in the Guidelines and technical reference that outline what is meant for the review in R1. Does a review require a detailed report or could a simple check box be used for a review?
No
For those Major disturbances there needs to be a mechanism for extending the timeframes without being penalized. Additionally 60 days might not be enough time to procure funds for the CAP. We are ok with the time requirement on R3.
No
There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn't a timeframe for the other entity to return the data requested and seems like this could cause an entity to not meet the timeframes specified in the requirements. Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely maner.
No
Our issue is not with the requested data but how the data is submitted. The current spreadsheet is very cubersome and needs to be reformatted.
No
It seems to us the SDT spends too much time on the VRFs and VSLs. An Entity is either compliant or not and verifying whether you are within so many days seems perculiar. Why was ten days choosen and not 30 or 45 days? The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph 81 project that is ongoing.
Yes
Yes
In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review

the system over a 24 month period, but doing this all the time seems overly burdensome. Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to mis classification of misoperations.
Group
Associated Electric Cooperative Inc - JRO00088
Brad Haralson
Associated Electric Cooperative Inc - NCR01177
Yes
Yes
Requirement R1.1.2 Replace: “Designate each Misoperation (if any)." With: “Designate each Misoperation (if any) in order to facilitate the reporting requirements in C-1.4 .” Rationale: Add clarity Concern: While AECI believes it understands the reason for R1.1.2's "Designation" existence, we question whether it can withstand the test of time and particularly hold-up to the proposed criteria within the "NERC Paragraph 81 Project".
Yes
Yes
Yes
No
On Page 11, the Severe VSL column's phrase containing “OR The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2. ”: Append: "and the Responsible entity failed to perform the subsequent R1 Part 1.3 as well." Rationale: We fail to see the reason for severity of impact otherwise.
Yes
Yes
Page 6, Line 1, Replace: "Analyze Misoperations Protection Systems" With: "Analyze Misoperations of Protection Systems" Rationale: Grammar and alignment with phrase from preceding bullet
Group
Operational Compliance
Ed Croft
Puget Sound Energy
Yes
Yes
No
Distinguishing between NERC and WECC time requirements and deciding which is "more stringent" is too confusing and time-consuming. WECC requirements should fully complement and enhance NERC requirements. The WECC quarterly reporting system already in place is essentially a good one. In a nutshell: Q1. W/in 60 days of end of Q1 - elements of PRC-004-3.R1, Q2. W/in 60 days of end of Q2 - CAP created and documented, Q3. W/in 60 days of end of Q3 - CAP in place or reason for no CAP.

Yes
Yes
Yes
Yes
No
Establishing the "most stringent" standard between WECC & NERC requirements will be difficult and time-consuming. Regional standards should fully complement and enhance NERC Standards. To that end, the NERC standard PRC-004 should be written such that the related WECC standards CAN fully complement and enhance it.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Pepco Holdings Inc
No
The existing definition of misoperation in the NERC Glossary of Terms indicates that if any individual component of a Protection System fails it is considered a misoperation. This new PRC-004-3 proposed definition modifies the definition by treating the primary and back-up protection schemes protecting a circuit element as a composite protective system. Individual component failures would not be considered a misoperation if the “overall performance of the composite Protective System for an element is correct.” We support this intent, but feel that the present wording in the proposed misoperation definition is not clear enough to adequately emphasize this distinction. The capitalized term Protection System, which is a NERC defined term, is used throughout this standard. However, the applicability of the proposed misoperation definition applies to the “Composite Protective System”, and not to each of the primary and backup Protection Systems individually. This point must be made very clear in the misoperation definition, since it is the foundation of the requirements in PRC-003-4. As such, either a new term “Composite Protective System” needs to be defined and the language in the misoperation definition and PRC-004-3 changed to reference this term; OR a qualifying paragraph could be included within the misoperation definition that states that “In the context of this misoperation definition a Protective System is considered to be the entire complement of protective system components (including both primary and backup protection systems) designed to protect a circuit Element.”
No
1) The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. The one who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO’s breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for also reviewing all GO protection initiated trips because the TO owns the interrupting device. This is unreasonable. The party who owns the Protective System(s) that protect the BES facility that was interrupted should be the one responsible for reviewing those Protective System operations and for developing any appropriate corrective action plans. Because of compliance implications the standard must make a very clear division of compliance responsibilities between the parties when interconnected Protective Systems are involved. The owner of the Protective System(s) that initiated the trip of the BES facility should be the one responsible for reviewing the operation for correctness (R1). The owner of the Protective System(s) whose misoperation led to the interruption of a BES Facility should be the one responsible for identifying the cause and developing and implementing a corrective action plan (R2,

R3, and R4). To make this perfectly clear we suggest re-wording Requirements R1, R2, R3, and R4 as follows: R1. Within 120 calendar days of an operation of an interrupting device which interrupts a BES Facility that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which protects the BES Facility that was interrupted shall: … R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall… R3. For each misoperation without an identified cause(s), the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall… R4. For each CAP or action plan, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall…. 2) What does R1.2 "Designate each misoperation" mean? Perhaps a more descriptive phrase would be "Designate which operations involve a Protective System Misoperation" OR "Identify and document each Protective System Misoperation".
Yes
The timeframes for R1, R2 & R3 are acceptable, since Requirement R3 provides a reasonable alternative if the investigation cannot be completed within the allotted 120 days in R1 (due to outage constraints, severe weather, resources, etc.). However, the commentary in the Rationale for R2 is misleading and incorrect with regard to the statement that 60 days is reasonable for the procurement of funds for a CAP. Capital dollars needed to fund larger CAP's (like other capital improvement projects) are budgeted for during a yearly budget cycle, usually in the fall of the preceding budget year. As such, unless the CAP was small and can be funded by an emergency blanket project it could take up to a year to get the necessary funding approved. We would suggest removing the procurement of funds from the R2 Rationale since it is not a pre-requisite for developing a CAP.
No
The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. See extensive comments on this subject in our response to Question 2 (Requirement R1).
Yes
No
The language in the VSL's for Requirement R2 should be changed to match the language in the Requirement. The present language uses the phrase "…following the completion of the investigation or receiving notification." That phrase should be eliminated and instead the phrase "…after the cause of the misoperation has been identified" should be inserted.
No
The proposed data retention requirements seem reasonable. However, the following comments are offered in order to improve clarity and avoid confusion regarding the wording of Measures M1 and M2. 1) The wording on Measure M1 should be revised to substitute Requirement numbers in place of Part numbers. For example, it should read "shall have evidence for Requirement R1.1 that…." Instead of "shall have evidence for Part 1.1 that…." In addition, because the list of evidence is not all inclusive it should end with the phrase "or other records". For example, "but is not limited to dated lists, logs, databases, or other records, that document…" 2) Measurement M2 requires evidence which must include a "dated CAP". It is unclear what a "dated CAP" means. Does it refer to the date the CAP was developed; the date the CAP is proposed to be completed by; or both? This needs to be clarified.
No
We agree with the timetable associated with the implementation of the new definition of a misoperation and for implementing the requirements in PRC-004-3. However, the following changes in the commentary included in the Implementation Plan should be made: 1) Re-word the definition of misoperation in accordance with the comments that we provided in Question 1 in this form. 2) Modify the list of "Facilities not included" to add Underfrequency Load Shedding (UFLS). 3) Modify the list of "Facilities not included" to expand on the Control section as follows: "Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)" Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to have to refer to the additional Guidelines and Technical Basis for most applications.
1) In Section 4.1.3 the wording should be changed to "Distribution Provider that owns a transmission

Protection System". This makes it consistent with the wording from previous versions of PRC-004, which recognized that it only applies to owners of Protection Systems that are applied to protect BES facilities. 2) A new Section 4.2.2.3 "Underfrequency Load Shedding (UFLS)" should be added under the Applicability Section "Facilities not included." Although UFLS schemes are Protection Systems covered under PRC-005 and are installed to preserve the BES from system underfrequency disturbances, they should not be included in this standard. Failing to specifically exclude them from this standard may lead to the assumption that they are by omission, included. Performance of UFLS schemes during system events are already covered in PRC-009, and as such do not need to be included in PRC-004-3. 3) Modify the list of "Facilities not included" to expand on the Control section as follows: "Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)" Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to have to refer to the additional Guidelines and Technical Basis for most applications. 4) On page 6 of the Background section of PRC-004-3 there is a typographical error on the second bulleted item, "Analyze Misoperations of Protective Systems for Facilities ...." The word "of" is missing. 5) Also in the Background section the reason for the exclusion of UFLS should be addressed. 6) In Requirement R2 first bullet item remove the phrase "for the identified Protection System component(s)". The term "component" should not be used, as it may lead to confusion. Individual Protection System component failures do not require a CAP unless the overall performance of the Composite Protection System for an Element was compromised. The bullet should instead read: "Develop and document a Corrective Action Plan (CAP) to address the identified misoperation that includes...". 7) By NERC definition each CAP must contain a timeline for implementation. Requirement R4.1 requires you to complete the CAP. Does that mean that to be fully compliant the CAP must be completed within the proposed timeline stated in the CAP? If so, there needs to be a mechanism to revise the proposed completion date when circumstances arise that prevent implementation in accordance with the originally proposed timeline (denial of facility outages, equipment delivery problems, major storm events, etc.) without being held non-compliant. R4.2 "implies" that the CAP can be revised (presumably including the proposed completion date) as long as it is documented. If this is a correct interpretation of R4.2 then there is a mechanism to revise a CAP's proposed completion date. On the other hand, this would allow the implementation of a CAP to be extended indefinitely by continuing to revise the proposed completion date. We doubt this is what the Standard Drafting Team intended. As such, the SDT may want to revisit the language dealing with revisions to a CAP.
Individual
NICOLE BUCKMAN
ATLANTIC CITY ELECTRIC COMPANY
Agree
PEPCO HOLDINGS INC AND AFFILIATES
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Pepco Holdings Inc. and Affiliates
Individual
Dale Fredrickson
Wisconsin Electric
Yes
No
1. In R1, the existing wording begins with: "Within 120 calendar days of an interrupting device operation ...". This wording does not specifically require a review in situations where an interrupting device fails to operate for a fault or abnormal condition. Perhaps the wording should be expanded to include these non-operations in the requirement as well.

Yes
Yes
No
Under Equipment Type: Add an equipment Type, such as "Generator Tie Line", to indicate the conductors from the generator step-up transformer high-voltage terminals to the substation/switchyard bus. These conductors are not considered transmission Lines, so the "Line" equipment type designation would not be appropriate for these.
No
We suggest that the Time Horizon for all four Requirements should be the same, "Operations Planning, Long-Term Planning". R1 is presently listed as Operations Assessment, Operations Planning.
No
In M1, the acceptable evidence for Parts 1.1 and 1.2 should also include "electronic or hard copy records", as it does for the notification required by Part 1.1.
Yes
In the Applicability section, in 4.2.3 relay functions not included, under 4.2.3.1 Control: add "Generator Excitation controls/limiters and turbine controls" to the existing exclusions list. The revised wording suggested is: "4.2.3.1 Control (e.g. controlled shutdown of generators, generator excitation controls/limiters, turbine controls, capacitor or reactor bank switching".
Individual
Nazra Gladu
Manitoba Hydro
No
Although we agree with most components of the definition, it is not clear to us what constitutes a “Failure to Trip”. For example, in cases of redundant “A” and “B” protection systems, if the “A” protection trips, but the “B” protection does not trip, would this be a misoperation reportable as a “Failure to Trip”? The first sentence of the second last paragraph of section A is not clear: “Misoperation of or associated with Special Portection schemes ….”
No
The wording of this requirement is not clear enough for us to determine if we agree with it. Specifically, in R1.1 it is not clear how extensive the review of each Protection System operation should be. In reading the words of the Requirement versus the words in the associated Measures, the review process seems a lot less onerous in the wording of the requirements versus the wording of the measure. Perhaps adding additional wording to the requirement, listing the steps that should to be undertaken during the review, or even providing a review template would provide additional clarity and consistency. An entity cannot be found non-compliant with a measure, only a requirement, so the requirement should be clear when read on its own without the measure.
No
The time limit for R2 should be changed from “60 calendar days of identifying the cause” to “180 calendar days from the misoperation”. Requiring the entity to track both the date of the operation (for R1) and the date the cause was identified (R2) seems like unnecessary work. This suggestion does not change the maximum time to complete R2.
Yes
Yes
No
Many of the requirements in this standard appear to be administrative or documentation based. It is therefore surprising to us that the VRFs and VSLs would be so high. As we understood it, NERC would

like to eliminate documentation-based requirements. Was that not the purpose of Project 2013-02 Paragraph 81? For documentation-based requirements, the VSLs appear to have very little leeway. For example, in R1 if an entity is 20 days late the VSL jumps to High. This seems disproportionate in comparison to the insignificant reliability impact that delaying the review by 20 days will have on the BES. An entity should be late by significantly more time to warrant going up to a High or Severe VSL. In terms of the VRFs, we do not agree that structured misoperation reporting will reduce misoperations and therefore feel that the VRFs should be lowered from Medium (R1, R2, R3) and High (R4) to Low and Medium. VSLs - R2 - The time frames should run from the 'identification of the cause(s) of each Misoperation' rather than completion of the investigation or receiving notification to be consistent with the requirement language. VSLs - R3 - High VSL and Severe VSL - the timeframes should run from the 'associated interrupting device operation' not the completion of the investigation to be consistent with the requirement language. Severe VSL - the word 'in' is missing from the first paragraph in describing more than 210 calendar days. 'Implement' should be removed from the second paragraph as this is not required in the language of the requirement; the 'ed' should be removed from documented.
No
In R1 and its associated measure, the measure implies that more work needs to be done in terms of the level of review that the requirement itself. The requirement is vague and could be interpreted differently by different people. This requirement and measure should both be re-worded to be more clear and consistent. (See related comments under Question 2.) Since for each Protection System operation, either R2 or R3 would apply, the words "As Applicable" should be added to these measures. Also, in M1 the wording "Part 1.1" is used. This should say "Requirement R1.1".
Effective Date - The language regarding the effective date needs to contemplate that Manitoba Hydro, like some other Canadian jurisdictions, will not have effective dates that are tied to Board of Trustees approval. We assuming that is what the proposed reference to 'laws applicable to such ERO governmental authorities' means but this is somewhat confusing. It would be more accurate to refer to the laws applicable to such functional entities. Background – We are not clear on whether the 'Background' section of the proposed standard becomes part of the standard when final or if it's just included at this stage when the proposed language is being circulated. Assuming it does become part of the standard, there are several issues with this section as drafted. There needs to be some sort of introductory sentence at the beginning of the paragraph that explains that PRC-004-3 is designed to replace PRC-004-2a and PRC-003-0 because otherwise there is no context for why these two standards are being discussed. The full name of the standard should be used in the fourth line (missing the words "Identification and Correction"). The NOPR is discussed without any explanation of what it is - the full name, date published, by FERC etc is needed. The same can be said for the reference to the SAR further down the page. The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". The terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above. R2 - More details should be provided regarding what level of detail is required when developing a CAP. Perhaps a template could be developed and attached to this standard. Also, the wording of R2 should be made more consistent with the wording of R3. R2 implies that a cause will always be identified. We suggest the words "For each Misoperation with an identified cause(s)" be added at the beginning of R2. R3 - The second bullet regarding the declaration should be re-worded to be consistent with the wording in R2. C. Compliance – (i) An acronym is assigned to CEA in 1.1, but it is used in full in 1.2. This is not necessary. (ii) The term "BES Protection Systems" is used in C. Section 1.2. It would be more accurate to use the term given in 4. Applicability, Section 4.2.1 "Protection Systems for Facilities that are part of the BES". (iii) C. Section 1.4 refers to PRC-004. It should refer to PRC-004-3. Technical Guidelines - Proper and complete references to document they refer to should be provided. For example, the July 2011 Risk Assessment doesn't indicate who published this or conducted this, where it is available, etc.
Individual
Bill Middaugh
Tri-State G&T

No
We understand why the parenthetical expressions are included in the first two parts of the definition since they clarify what is excluded from the definition. However, the parenthetical phrase in the third part of the definition seems to be another expression of what is to be considered a Misoperation, but it is not consistent with the non-parenthetical definition. We suggest changing it to “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance is not used to meet the performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.“ We have a question regarding the phrasing “required to meet the performance requirements of the TPL standards” (changed in our recommended language). Does this mean that a simulation has been performed that determines that high speed protection is required to meet TPL standard requirements? Or does it apply to the slower clearing if the reduced performance results in a failure to meet the requirements of the TPL standards regardless of whether it had been discovered and documented? While we did not base our “No” answer on the following, our belief is that the exclusions of individual Protection System component failures as long as the total Protection System operates to clear the Fault in the time and zone for which it was designed may lead to a reduced level of reliability to the BES. Failures of components may be easily overlooked if the entity doesn’t review the event closely enough to discover misoperating components because the aggregate system operated correctly. But we recognize that there is unclarity regarding the definition of Protection System and that unclarity could lead to considering the overall performance of the aggregate Protection System, which was the interpretation used by the drafting team.
Yes
Yes
No
It is not clear how the owner of the interrupting device that operates can designate and investigate the Misoperation of a Protection System component owned another entitity, but that seems to be what Parts 1.2 and 1.3 require. One solution would be to divide Requirement R1 into two requirements as described below. “R1. Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall identify and review each Protection System operation. If the entity suspects a Misoperation of a Protection System component owned by another entity caused an unnecessary interrupting device operation, notify the owner of that Protection System component and provide any requested investigative information.” “R2. The owner of any Protection System identified as misoperating in Requirement R1 shall: 2.1 Designate each Misoperation. 2.2 Investigate each Misoperation and document the findings including a cause for each Misoperation, if identified. 2.3 Provide its Corrective Action Plan (CAP) to the other entity and notify the other entity upon completion of the CAP if the Protection System that Misoperated caused that other entity’s interrupting device to operate.”
Yes
Yes
Yes
Yes
Individual
John Canavan
NorthWestern Energy
Yes

Yes
No
We have a concern on R2 on the 60 calendar days to make a CAP (corrective action Plan). Making a plan with a timeline in 60 days poses an issue where budgeting is required to perform a major relay upgrade to fix a problem. We fear this wording could expose us to potential penalties for not meeting a CAP's stated time line that would be made before the budgeting approval and scheduling process is completed.
Yes
Yes
Yes
Yes
Yes
Individual
Jack Stamper
Clark Public Utilities
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
I am confused on the requirement to provide a quarterly report. In the current draft the reference to this requirement appears in Section 1.4 of the Compliance Monitoring Process. This requirement does not appear to be in the Requirements and Measures section. The quarterly reporting also does not appear to be in the Violation Severity Levels. So it appears that in this draft, there is no real "Requirement" that a quarterly report be submitted and there is no assignment of a violation to those TOs, GOs, and DPs that do not submit a quarterly report. Is that so or am I missing something? This seems odd. If TOs, GOs, and DPs are supposed to submit a quarterly report, why isn't this included in the Requirements? Please eliminate this ambiguity. Either add the reporting to a Requirements provision or get rid of the reference to the reporting requirement in the Compliance Monitoring section.

Individual
Thad Ness
American Electric Power
Yes
No
AEP believes that PRC-001, rather than PRC-004, is the most appropriate standard to address an entity being required to notify another entity of protection system disturbances involving Misoperations or otherwise. If the drafting insists adding such requirements to PRC-004, we recommend making the following changes to R1: a) For 1.1, striking the language “If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information” so that it simply reads “ Identify and review each Protection System operation.” b) Inserting an additional requirement inbetween 1.2 and 1.3 that simply states “If the investigating entity determines Protection System component(s) owned by another entity contributed to the Misoperation, the investigating entity shall notify the owner of that Protection System component(s) and provide any pertinent information.”
No
In general, AEP supports the idea of time limits in regards to R1, R2, and R3. However, though these proposed limits might be reasonable and attainable under normal operating conditions, the proposed time limits for R1 and R3 would not likely be reasonable during major distubances and significant events. The volume of analysis required in these situations is simply too great and complex to complete in the time limits proposed. Either the time limits proposed need to be extended to accommodate analysis during major distubances, or else there must be provisions for granting time extensions when major events occur. For example, if there was an event that was in scope under EOP-004 disturbance reporting, that entity could be afforded the flexibility to work out the allowed time limits with their Regional Entity. In addition, an entity’s allowed time window to repond should not begin until it has officially received notification.
No
Please see our response to Question 2 where we suggest changes to R1 regarding such situations.
Yes
We encourage the SDT to ensure this form is consistent with SPCS form.
No
The R1 VSL's should use percentages to determine the severity level. As written, a utility performing 99% of the identification, review, notification, designation and documentation correctly would receive a severe violation. In the R4 VSL's, "The responsible entity failed to maintain records of a CAP or action plan" should be moved from severe to medium. The penalty for failing to document should be less than the penalty for failing to implement.
Yes
No
AEP does not have problem with the implementation plan; however, the implementation duration of six months is not consistent with the response in the SDT’s Consideration of Comments which indicate it is 12 months.
The following excerpts from the "Consideration of Comments" document should be added to item "(3)" of the "Guidelines and Technical Basis" section to clarify the intent of the "Slow Trip" category: “In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection for meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported. However, even if high speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip).” Facilities 4.2 - Should the text “Also see Guidelines and Technical Basis section for detailed examples” be taken out of 4.2.3.1 and applied more broadly to the standard? In the first bullet of R2, may an evaluation of the CAP's applicability to the entity's

Protection System at other locations result in no additional actions being taken? Is the "evaluation of the CAP's applicability to the entity's Protection System at other locations" part of the quarterly reporting?
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst Abstains and offers the following comments for consideration: 1. Requirement R1 and subsequent requirements a. ReliabilityFirst believes Requirement R1 and subsequent requirements rely on the operation of an interrupting device and the identification by its owner that a Protection System operated and whether it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard. First, the owner of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process. Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it. 2. Requirement R1, Part 1.1 a. ReliabilityFirst believes the second sentence in Part 1.1 is a separate thought and recommends removing it and creating a new Part 1.2. ReliabilityFirst recommends the following for consideration for the new Part 1.2: “Notify the owner of that Protection System component and provide any requested investigative information if the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation.”
No
ReliabilityFirst Abstains and offers the following comments for consideration: 3. Requirement R2 a. ReliabilityFirst believes the phrase “Within 60 calendar days of identifying the cause(s) of each Misoperation” relates to the designation of the cause of each Misoperation as identified in Requirement R1, Part 1.3 or as identified through implementation of the action plan per Requirement 4, Part 4.1? If so, ReliabilityFirst recommends add the parenthetical “(per Requirement R1, Part 1.3 or Requirement R4, Part 4.1)” to Requirement R2 in order to further clarify when the timing of the 60 calendar day window begins.
ReliabilityFirst Abstains and offers the following additional comments for consideration: a. ReliabilityFirst believes there are extra and unneeded deadlines in the standard that do not provide a reliability benefit. b. ReliabilityFirst believes there is a potential for late identification of Misoperations which will result in violations even if they are not particularly significant to grid reliability. For example, capacitor bank trips occur every day as part of normal switching. It may not be obvious if it was by a Protection System Misoperation, particularly if a relay is used for multiple purposes like ON/OFF switching control and protection. c. ReliabilityFirst has a concern that there is no maximum time to complete CAPs listed in the draft standard. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause should be either mitigated or the CAP completed in something like 6 – 12 month time period.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No

We are concerned about what "Slow" is and if the drafting committee is creating a new kind of misoperation or whether this is something that might just be found as a result an investigation of an existing type of misoperation.
Yes
Group
Souhwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Southwest Power Pool
No
We need some clarification around section 3 Slow Trip During Fault. Is this intended to address the future changes around the Upcoming TPL standards? We need clarification on what is meant by referencing the TPL performance Standards in this section.
No
We would like some clarification on the review identified in R1. Based on the type of review that 120 days may or may not be enough time. We would request some example(s) be added in the Guidelines and technical reference that outline what is meant for the review in R1. Based on the examples the drafting team develops we can determine if the 120 days is appropriate. We also don't agree that 120 days is enough time for those instances when major disturbances IE storms hurricanes tornadoes. This needs to be addressed in the requirement itself and would request that there be an extension that could be requested for those types of events reported in DOE 417 and EOP 004.
No
See above comment. For those Major disturbances there needs to be a mechanism for extending the time frames without being penalized. Additionally 60 days might not be enough time to procure funds for the CAP. We are OK with the time requirement on R3.
No
There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn't a time frame for the other entity to return the data requested and seems like this could cause an entity to not meet the time frames specified in the requirements. Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely manner.
Yes
No
Most entities will be compliant or not. We don't agree that the severity level needs to be raised based on being an additional 10 days late. We would suggest revisiting this section and possibly make the interval 30 days in between a severity increase. The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph 81 project that is ongoing.
Yes
Yes

Can Attachment 1 be tabbed format or something easier to use than the long spreadsheet provided? Also we don't agree that the quarterly interval and if this is in conjunction with TADS and GADS then both of these are only reported annually. In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review the system over a 24 month period, but doing this all the time seems overly burdensome. Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to mis classification of misoperations. Protection System operations which occur with the protected Element out of service, that trip any in-service Elements are Misoperations. Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, construction or commissioning activities.
Individual
Robert Dintelman
Utility System Efficiencies, Inc.
Yes
This standard revision is solid and specific, and should be MUCH more straightforward to audit/enforce, since it specifically requires the analysis of all operations. A comment is needed concerning the lack of any exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Yes
The standard should recognize the need for exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Yes
See previous comments for questions 1 and 2.
Yes
Yes
Yes

Yes
Yes
Group
Detroit Edison
Kent Kujala
Detroit Edison
No
No, Dteroit Edison disagrees with "Slow Trip - Other than Fault." We feel that the SDT should consider, with respect to many of the Generating Unit trip conditions that are given, that there may not be adequate resolution of time and current\voltage\etc. monitoring. If monitoring with as fine a resolution as is required to analyize speed of operation, it should not be considered a misoperation.
Yes
Yes
Yes
Yes - SDT did an excellent job with joint ownership issues.
Yes
Yes
Yes
Yes
Overall, the draft standard is good and we already comply with most of the requirements as a general practice. The concern is around ability to properly anazlize and determine of operations, specifically around generation, would be considered slow. As of today, there is not adequate monitoring (and many of the conditions are far too dynamic to properly determine what the proper operating time should have been) to determine how quickly a relay responded to a "other than fault" condition. Would recommend a "yes" vote if there was wording stating that it is not a misoperation if the data that exists is not of a fine enough resolution to prove a relay was slow.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Agree
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Individual
Timothy Brown
Idaho Power Co.
Yes
We believe the previous comment period has produced a thorough definition of a Misoperation.
Yes
Yes, it makes sense that the owners of the interrupting device and protection equipment should be

the lead on the investigation.
Yes
Yes, they seem reasonable.
Yes
Yes
Yes
Yes
Yes
Individual
Angela Gaines (for Kellie Cloud)
Portland General Electric Company
Yes
Yes
No
Managing multiple deadlines based upon event date is difficult and does not align with quarterly reporting requirements (also see response to question 5). If more stringent deadlines are to be applied, there should be separate deadlines for identification of misoperations (less than 120 days) and identification of the cause (more than 120 days). Complex events affecting multiple work groups or entities as well as those involving equipment failure may result in entities taking more than 120 days to determine the Root Cause. Often misoperations result in the need to send protective relays back to the manufacturer, but relay manufacturers have no requirement to meet these deadlines. Not allowing sufficient time to determine the Root Cause will result in more events being referred to R3 (no identified cause) or CAPs being developed based upon incorrect causes. Complex events affecting multiple work groups or equipment failure may result in an entity taking more than 60 days to develop a CAP even after a cause is identified. Not allowing sufficient time could result in less than desirable CAPs.
No
There is a requirement to notify another entity if their component is suspected of contributing to a misoperation, but there is no requirement to respond to such notifications. Accountability to report back to the entity providing the notification should be included to ensure that entity can maintain its own compliance. Events involving transfer trip on interconnections, for example, could involve misoperations of equipment owned by both entities and require significant cooperation during the investigation phase.
No
The fields listed in Attachment 1 are sufficient. However, the quarterly reporting requirement is buried under the Compliance Monitoring Process, but should be a clear separate requirement for the registered entities under the standard. The reporting requirement R2 of UVLS standard PRC-022 is slated to be retired per Project 2013-02, but 4.2.2 specifically excludes UVLS from this standard. This could result in UVLS misoperations not being reported.
No
Severe VSLs should not be applied for lateness, only for failure to perform the required activity.
Yes

Yes
First comment: 4.2.2 excludes UVLS from this standard due to the existence of PRC-022, but it is expected that PRC-022 will be superseded much like its UF counterpart PRC-009. Rather than requiring a revision of PRC-004, 4.2.2 should be worded such that UVLS schemes would be covered by PRC-004-3 at such time as PRC-022 is retired. Second comment: Additional resources and signification database modifications will be required to ensure proper documentation of compliance.
Individual
Martyn Turner
LCRA Transmission Services Corporation
Yes
Yes
No
For the R2 time basis, the 60 day period for developing a CAP is reasonable; however, identifying the specific date the cause was identified could be subjective and could lead to an unnecessary violation due to a simple clerical error. We would recommend stating the CAP should be developed within 180 days of the interrupting device operation (the event). We do not view R3 as being necessary and could even put an entity at conflict with R1 and R2 (i.e. the cause has not been determined within 120 days; however, the investigation continues and at day 140 the cause is determined and the entity is now in violation of R1) An entity should be able to complete all investigations within R1 requirements of 120 days, even if the finding is unknown. There is no benefit to extending the investigation out 180 days and beyond. Similarly, for an unknown cause a corrective action plan to plan and install controls to monitor the relay scheme to identify the cause of a repeat failure can be planned and executed within the requirements of R2 and R4.
Yes
Yes
No
For R1, R2 and R3, we do not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the “Find, Fix, and Track” category, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement. We have no suggested change for R4.
Yes
Yes
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes

Ingleside Cogeneration LP believes that the modification is an improvement over the previous draft. However, we still would like to see a commitment from the ERO-Reliability Assessment and Performance Analysis (RAPA) Group that they will align their definition when PRC-004-3 takes effect. Although the differences are minor, a difference in the criteria may require the industry to make two separate determinations on whether a relay-related event should be identified as a Misoperation.
No
Ingleside Cogeneration LP sees this requirement as specifying “how” to identify a Misoperation, not “what” comprises a Misoperation. Although, we understand that a robust process would include a prefunctory review of every relay operation, the need to capture and document each one in a manner satisfactory to an auditor adds no reliability benefit in our view. In fact, the vast majority of relay operations are NOT Misoperations and have a well-understood cause that is known immediately (e.g.; equipment fault). Based upon this thinking, PRC-004-3 R1 should only require an event be captured that is (a) known to be a Misoperation at the time of the relay action, or (b) the cause remains unknown an hour afterwards. This should greatly reduce the number of incidents that need to be recorded – and allows focus on those which do not have a simple resolution.
Yes
Ingleside Cogeneration believes that 120 days is generally sufficient to determine the root cause of most Misoperations – or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The additional 60 days to develop a corrective action plan time frame is acceptable to us as well.
No
It is not clear to Ingleside Cogeneration LP how a situation is resolved where interconnected Protection System owners disagree with the causes or mitigation of a Misoperation. We can easily envision a scenario where we have been informed by a neighbor that one of our relays contributed to a Misoperation – which we do not find to be the case. This seems like it could result in an audit finding that we did not report a Misoperation based upon someone else’s evaluation. There may be recourse in existing escalation procedures to engage the Regional Entity and even NERC at some point to resolve a conflict of this nature. Whatever the solution, we firmly believe that this pathway to resolution must be made clear as part of this project. If left open, the most subtle interaction issues will result in finger pointing in all directions – an unproductive use of everyone’s time. Furthermore, problems of this nature are likely to identify previously unknown failure mechanisms, which could help all industry stakeholders. The Regions may have access to technical specialists who are best positioned to assist with an evaluation of this level of complexity.
Yes
Ingleside Cogeneration LP agrees that the data listing is generally consistent with the existing process.
Yes
Yes
Yes
Individual
Saul Rojas
New York Power Authority
Yes
Yes
Yes

Yes, Yes
No
Need to explain the relevance of the TADS and GADS data to the calculation of the metric.
Yes
Yes
Yes
None.
Group
Tacoma Power
Chang Choi
City of Tacoma and Tacoma Public Utilities
No
It is still not completely clear what is meant by ‘intended’? The wording for Slow Trip – During Fault is awkward. For example, consider changing “...if high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems” to “...if high-speed performance is required to meet the performance requirements of the TPL standards or coordination requirements with other Protection Systems”; in other words, remove ‘by.’ Under the proposed, revised definition of a Mis-operation, it is unclear if a Mis-operation resulting from mis-coordinated relays would normally be categorized as Slow Trip or Unnecessary Trip. What is meant by ‘on-site,’ as in the definition of Unnecessary Trip – Other Than Fault? Specifically, what if a remote terminal is inadvertantly tripped by means of a communications system during maintenance, testing, construction, or commissioning activities; technically, the interrupting device that operated is not “on-site.” Additionally, what if an operation occurs during initial energization or loading following maintenance, testing, constuction, or commissioning; it seems that because the operation occurs with personnel still on site that this should not be considered a reportable Mis-operation, especially since the Element is just being returned to service.
Yes
The general approach and intent is supported. However, how can an entity prove that it identified all BES Protection System operations? While processes should be in place to promptly identify all BES Protection System operations, it is feared that significant cost and resources will be required to “ensure” that all BES Protection System operations are identified, which could divert staff from key reliability activities. A similar concern exists for identifying all Mis-operations. Recognizing that even the proposed, revised definition of a Mis-operation could be interpreted in different ways in some cases, it is conceivable that some entities could begin over-reporting possible Mis-operations out of an abundance of caution. It should also be recognized that not all Mis-operations are of equal impact to the reliability of the BES. Over-reporting by entities to avoid even the possibility of sanctions could pose a burden on Regional Entities and NERC and might distract the industry from correcting the key Mis-operations impacting BES reliabity.
Yes
No
Remove the second sentence under R1.1. At minimum, consider moving this sentence to R1.3 or creating a new R1.4. As written, this sentence is included in a sub-requirement that, in the overall process, has not yet even required designation of any Mis-operations. Presumably, at least part of the reason that this sentence was included was to mitigate any concerns that Entity A will wait before notifying Entity B, such that Entity B has little time to investigate before the deadline. However, as written, R1.1 would still permit Entity A to notify Entity B within 120 calendar days of the interrupting

device operation, which would leave Entity B no time to investigate before becoming non-compliant, since per R1 the clock for investigation starts when the interrupting device operated. The bottom line is that, if Entity A suspects that a component owned by Entity B contributed to a Mis-operation, it is in Entity A's interest to take action; it is recommended that there be no explicit regulaotory requirement for notification.
No
Why does an entity need to provide the Date Reported? It seems like the Regional Entity could provide this information based upon when they receive it. The person assembling the reporting data may not be the one actually submitting it to the Regional Entity, and the submittal date may not coincide with dated that the reporting data is assembled. Therefore, two individuals may need to be involved. While not a lot of extra work, it is an additional administrative step in the process that seems to provide little value to reliability. Additional information, or at least a reference to additional information, should be provided to describe TADS and GADS reportable events. It seems like the following fields could be consolidated into one: Event Description/Analysis and Protection Systems/Components that Misoperated. What penalties would be likely if an entity, acting in good faith, provides information that is later determined to be incorrect and is then updated in another reporting period? Do all Mis-operations need to be submmitted with Submittal Type entered as 'Remove' before they no longer need to be resubmitted? Or, does the final submittal only need to have one of the following in the Resolution Status field, even if the Submittal Type is 'New' or 'Update': 'Corrective Action Plan – Completed,' 'Action Plan – Completed,' or 'Declaration – Completed.' If a declaration is made, or an action plan is completed, and reported (submitted), does the associated Mis-operation need to be continually re-submitted while the status is 'Declaration – Completed' or 'Action Plan – Completed'? It seems like these two statuses are still somewhat open-ended. Remove double slash in "Corrective Action Plan//Declaration Development Date."
No
Under the Lower and Moderate VSLs for R3, the description ends with "...following the associated interrupting device operation " Under the High and Severe VSLs, the description ends with "...following the completion of the investigation." Was this difference intended? It seems that there should be consistency.
No
Referring to M4, change "...that must include..." to "...that may include..." Referring to Evidence Retention, the first paragraph appears to conflict with the second. In the first paragraph, the draft standard says, "For instances where the evidence retention period specified below is shorter than the time since the last audit..." However, in the second paragraph, the draft standard says "...shall keep data or evidence to show compliance with...since the last audit..." Given the language in the second paragraph, how can the evidence retention period be less than the time since the last audit, as the first paragraph suggests may be possible?
Yes
Under Applicability (comment box to side), change 'RMS' to 'RAS.' Why does "(e.g., data collection)" need to be included under 4.2.3.2? Data collection does not operate anything. Referring to the second bullet of page 5 (red-line version), change "...Misoperations Protection..." to "...Misoperations of Protection..."
Individual
Mark F. Draper
Exelon Corp.
Yes
• Exelon would like to see stronger wording to very clearly state that the protection system is to be evaluated as a composite system (primary and backup are part of a single composite system). • Under the Misoperation definition section: a. Item 1 Failure to Trip – During Fault ... change "for an Element" to "for the Element". b. Item 2 Failure to Trip – Other Than Fault ... change "for an Element" to "for the Element". c. Item 6 "Unnecessary Trip - Other Than Fault" - needs more clarification as to whether or not this includes personnel error (e.g. open test switches inadvertently).
Yes

• The Application Guidelines should be part of the Standard because they provide better clarification of the activities and timelines associated with R1, R2 and R3. • For R2: Replace “Explain in a declaration why corrective actions are beyond the entity’s control or would reduce BES reliability” with “Explain in a declaration if no further corrective actions are required and your rationale.” “beyond the entity’s control” may be subjective. • Suggest including the following statement based on wording in the Application Guidelines concerning a no CAP declaration: “A condition identified during an investigation that is addressed by existing maintenance activities would be justification for taking no additional corrective action.” • Exelon comments: Suggest revising the time limit verbiage as follows in order to provide more clarity: R1 Within 120 days of the event, review to determine whether the operation was correct. For any misoperation, identify and document the cause. R2a If after the initial 120 days a cause is determined for the misoperation, within 60 days - Develop a corrective action plan for the identified protection system component Or Explain in a declaration if no further corrective actions are required and your rationale R2b If after the initial 120 days no cause was determined for the misoperation, within 60 days - Develop an action plan that identifies additional investigative actions to determine the cause Or Explain in a declaration why no further action will be taken R3 Within 60 days of determining a cause under requirement R2b – Develop a corrective action plan for the identified protection system component Or Explain in a declaration if no further corrective actions are required and your rationale.
Yes
• The standard needs to make it clear that an entity needs to provide information to another entity within a specified time period, e.g., a TO needs to provide information to a GO on a transmission line trip, within limitations of the FERC Standards of Conduct.
No
• The list is good for a 50,000 foot level view of analysis results. Protection Systems are too complex and dissimilar to obtain meaningful analyses at the level of the Attachment. Also, understand that the purpose of Attachment 1 is not to trouble-shoot misoperation, only to provide a database of types of misoperations as a performance indicator. • Item C1.4 - Additional Compliance Information requires the quarterly Misoperation Data - Attachment 1 to be submitted within two calendar months following the end of each calendar quarter. This does not allow for the time limits specified in requirements R1, R2, and R3 for investigating, identifying and creating a CAP for the associated misoperation.
Yes
• Please confirm that the Application Guidelines material will be kept with the standard. One example of why this is important is so that the statement regarding natural disasters and extenuating circumstances is included. Specifically, the Application Guidelines currently contain the following: “In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.”
No
• Measure M4 – change “must include” to “could include“. So the new wording is as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that could include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, completion of actions and revisions for each CAP or action plan; dated work management program records, dated work orders, or dated maintenance records.”
No
• Implementation date: This standard is to go into effect on the first day of the first calendar quarter, 3 months after Board of Trustees adoption. This does not allow adequate time for the necessary programmatic and procedural changes required for a large organization. Suggest more time be allowed – such as one year after Board of Trustees adoption.
• In the Introduction section, Applicability includes Distribution Provider. If this standard is for Protection Systems that are part of the BES, does a DP belong in the list of Functional Entities? • To what extent would an entity have to defend a determination that a system operation is considered to be a correct operation, if there is limited data to make the determination? This should be addressed in the Application Guide. • The Application Guidelines state that reverse power relay operations used for

control of a generator (when a reverse power relay is used to trip a breaker during generator shutdown) are “not included in the definition of Misoperation and its operation would not be reviewed under this standard.” Since it can be debated whether a reverse power relay is used for control or generator protection, the Application Guidelines should remove the verbiage about the “control” aspect of this relay. The Application Guidelines should just state that “expected reverse power relay operations, such as those encountered when a generator comes off-line, would not be required to be reviewed under this standard.” This comment is not intended to remove the entire Application Guidelines discussion on control aspects of relays being excluded from needing a review under this standard. Rather, the intent of this comment is to revise the Application Guidelines so as to preclude any discussion over whether a reverse power relay is a control device or a protective device – and just list the exclusions for this relay, and any similar generator relays. • Exelon requests that the SDT clarify within the Standard that the interrupting device itself referenced in the Standard draft is also considered an element of the Bulk Electric System. Specifically, please clarify that a device on a radial line that does not affect the BES is excluded from this requirement. Suggest that this clarification be added to the Application Guidelines. • PRC-004 Requirement R1 requires that each Generator Owner identify and review each Protection System operation associated with an interrupting device operation. The SDT should re-evaluate this requirement as it implies that all generating facilities have established monitoring systems that will capture such events. Although some generating units do have existing monitoring systems (such as Disturbance Monitoring Equipment) not all generating units have such capability nor are they all required to install such monitoring equipment in accordance with existing FERC approved Standards. • Exelon agrees with the SDT revision to remove the requirement in R1 that an entity shall have and implement a "procedure" to identify and address all Protection System Misoperations within its system and that an existing Corrective Action Program will meet the intent of the Standard; however, the SDT response to the Exelon and Constellation comments submitted in the previous draft (Consideration of Comments in response to the 6/10/11 – 7/11/11 draft) is inaccurate and warrants clarification. The original Exelon comment was: “Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management." The SDT response documented is as follows: “Thank you for your comments. These requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.” As a point of clarification, the SDT response that references Order 706-B indicates that BES electrical systems would not fall under NRC regulation. In summary, FERC Order 706-B “clarifies that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory ‘CIP’ Reliability Standards approved in Commission Order No. 706.” In November 2010 FERC and the Nuclear Regulatory Commission (NRC) came to understand that because changes in electrical power output affect nuclear reactor core reactivity, NRC would have oversight of these “balance of plant” systems. FERC formalized this understanding in FERC Order issued March 10, 2011, Docket No. RM06-22-014, “...we find that the NRC’s cyber security rule appears to cover all balance of plant, and no balance of plant at a U.S. nuclear power plant has been found to be subject to NERC’s CIP Standards.” It should be noted that the NRC required Corrective Action Program (regulatory requirement information as documented above) applies to all systems, structures and components of a nuclear generating unit and therefore should be an acceptable method of complying with the revised Standard.
Group
El Paso Electric

Rhonda Bryant
El Paso Electric
Yes
El Paso Electric Company (EPE) agrees with the definition with a slight change to the wording of the titles of "Failure to Trip – Other than Fault" and "Slow to Trip – Other than Fault". EPE believes in these applications the titles should read Failure to Operate – Other than Fault and Slow to Operate – Other than Fault. There are scenarios, in the case of a power swing, where a device or element may be set to block a trip.
No
EPE believes more clarity is needed in this requirement as to responses required by other owners when their component may have contributed to the misoperation of the Protection System. For example, Entity A's protection system operates, however Entity B's component contributed to the misoperation. Entity A notifies Entity B of such component failure. There isn't a specified timeline, within the 120 days, requiring Entity B to notify Entity A of its information regarding such component, allowing Entity A to timely complete its analysis and report of the operation of its Protection System. Additionally, what would Entity A's response be if Entity B doesn't acknowledge their component's contribution to the misoperation?
No
See EPE's comment in Question 2.
No
See EPE's comment in Question 2.
No
EPE believes the columns in Attachment 1 requesting Event Analysis Completion Date; Corrective Action Plan/Declaration Development Date; or Action Plan/Declaration Development Date does not contribute to improving protection system performance.
No
Based on the NERC's definition of High – Violation Risk Factor, EPE believes the assignment of High Risk to R4 does not seem to be warranted. R4 combines the implementing and documentation of any corrective actions in connection with a misoperation, and does not impact the reliability of the BES. EPE believes a separation of the implementing process and documentation requirements may provide a solution.
EPE believes additional clarity under the "Additional Compliance" section would be helpful as it relates to reporting misoperation data. EPE believes the insertion of some additional language may provide clarity, such as "…..shall submit data identified on Attachment 1 for misoperations identified within a quarter…"
Group
Electric Reliablity Compliance
Sara McCoy
Salt River Project
Agree
Lower Colorado River Authority (LCRA)
Individual
Mark R. Jones
Potomac Electric Power Company
Agree
Pepco Holdings Inc. and Affiliates
Group
TVA Transmission Operations and Maintenance
H. Pat Caldwell

Energy Delivery
Yes
No
Comments: The requirement to review and document each Protection System Operation is overly burdensome to those utilities with heavy lightning exposure. TVA has approximately 400 interruptions a year due to lightning. To review, verify, and document each one of these to ensure whether or not a misoperation occurred within 120 days, especially during the spring-summer storm season and then find a cause for each misoperation can be overwhelming. For example, the April 27, 2011 storms took months of restoration before investigation of possible misoperations could begin. That particular storm caused about 20 misoperations. TVA would like to see the window of time extended to 180 days.
No
The time limits do not allow for equipment that is difficult to get out of service to allow testing/troubleshooting to investigate and develop a CAP. Often transmission line of transformer bank outages can only be obtained during very limited time frames or must be scheduled months in advance. Only after the investigation is complete can the final CAP be confirmed, depending on what is found during investigative outages. The 180 days in some cases may need to be at least 270 or more for some investigations.
Yes
Yes
No
The limits and time horizons are too restrictive and do not take into account if an entity is making a good faith attempt to investigate a misoperation and for reasons outside of its control, cannot meet the arbitrary numbers in this draft. There needs to be exemptions made for the safe operation of the transmission system to override the limits. Maybe some sort of deferral process with proposed dates to replace the time horizons when system conditions cannot support the necessary work required to investigate and correct.
Yes
Yes
Individual
Mike Weir
Dairyland Power Cooperative
No
The SDT should clarify whether UFLS is or is not covered by this standard. The “Consideration of Comments” indicates that it is. If so, it is suggested that the SDT consider adding underfrequency to the list of non-Fault conditions listed in items 2. and 4. in the Misoperation definition. If not, it would help to clearly state that it is “excluded” in Section 4.2.2.
No
Additional clarification should be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
No

R1 requires the identification and review of an operation, as well as the designation and investigation of a Misoperation, all within 120 days whereas R2 requires the development of a corrective action plan within 60 days of identifying the cause of a Misoperation. It is a concern that these proposed timeframes will create a disincentive for early identification of Misoperations. As an example, if a Misoperation is identified on day 2 after the incident, the corrective action plan must be developed no later than day 62 following the incident. However if an entity were to delay identification of the Misoperation until day 120 after the incident, the corrective action plan would not have to be developed until day 180. To prevent deterring entities from identifying Misoperations sooner, it suggested the drafting team consider requiring the corrective action plan by day 180 regardless of when the misoperation cause was officially identified. Doing so would avoid entities having to worry about the official date of Misoperation identification.
Yes
Yes
Yes
Yes
Yes
R2 and R3 the second bullet is administrative and redundant, and does not aid in the protection of the BES. Recommend removing the second bullet from R2 and R3. This is captured within the first bulleted item. R4.2 is administrative and does not aid on the protection the BES. Recommend removing R4.2
Individual
Marie Knox
MISO
No
The SDT should clarify whether UFLS is or is not covered by this standard.
No
It is unclear on what “Designate each Misoperation” means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
No
Comments: We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to provide reports within the allotted time frame. Priroritization should be given for events that are suspected to be misoperations based on the entities’ judgment.
No
It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
No
As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES.

Clarification should be provided of what approvals or coordination the identitfied responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.
Group
Santee Cooper
Terry L. Blackwell
South Carolina Public Service Authority
No
While the purpose of the clarifications in the misoperation definition is understood, the proposed definition seems to use the term “non-fault condition” differently in different sections. For items 2 and 4, it says “a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, overexcitation, or loss-of-excitation.” Similar wording is used in 4 “such as a power swing, under-voltage, overexcitation, or loss-of-excitation. However, in 6, the terms “other than fault” and “non-fault condition” are also used, but, it would be expected that the definition here should be broader than in 2 and 4, to include when a misoperation occurs for no reason (no abnormal condition). It seems like this could lead to a misinterpretation of number 6, since it uses the same term “non-fault condition” as in 2 and 4. We suggest having the following 4 categories, which would still ensure that the “non-fault conditions” are still included: 1. Failure to Trip – A failure of a Protection System to operate for a Fault within the zone it is designed to protect or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System was intended to operate. 2. Slow Trip – A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect or for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation. 3. Unnecessary Trip – A Protection System operation for a Fault or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System is not intended to operate. This excludes any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. 4. Unnecessary Trip – Normal system conditions - A Protection System operation when no fault or non-fault conditions are present (such as a power swing, under-voltage, over excitation, or loss of excitation). There may be other appropriate wordings for number 4.
Yes
No
We agree with the need for NERC and the regions to review the timeliness of the analysis of misoperations. However, the regional entities, based on the RAPA template for reporting misoperations and the quarterly reporting of these misoperations, already are getting dates from the entities for the date of the misoperation, the date the corrective action was completed or, if not complete, the expected completion date. Without any additional administrative manpower commitments, the regions can already assess through the spreadsheet how long each misoperation took to completion and question anywhere timeliness seems to be a factor. They can even assess the timeliness of the original analysis of the operation (and identification of any misoperations) by checking when a new misoperation is reported against the reporting period it should have occurred in. Therefore, it seems counterproductive to prescribe timelines per misoperation, that will mean that entities have new much larger administrative burdens put on their technical staff just to document that each analysis of each operation and misoperation meet the number of days allowed. There could still be a maximum limit of what is allowed time-wise without having all of the individual date requirements. For example, additional documentation could be tied to, say, if the corrective action is not complete after the 2nd quarter that the misoperation was submitted to the regional entity. This will allow the finer detail focus of both the individual companies and the regions to be the more complicated and longer timeframe misoperations, while still supplying data (but not more than is needed to find and correct the misoperation) about the other misoperations that occur.
No
Initially, the investigation/reporting burden should fall on the owner of the interrupting device.

However, once it is determined which entity’s equipment caused the misoperation, the burden of reporting should shift to that entity.
No
The Incorrect Setting/Logic/Design Errors category needs to be split into separate categories to improve the data analysis. As relays get more complex, more of the protection system is becoming internal to the relay, and so this has become a disproportionately large category.
No
As stated in Question 3, we do not feel the timetables involved are needed for ensuring operations and misoperations are handled appropriately. That being said, for R1 and R3, 30 days is a quick change from Lower to Severe. Suggest making the change for R1 and R3 should be proportionate to R2 (about 50%).
Yes
Yes
Need to clarify how misoperations that are still not completed are going to be transitioned.
1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP “includes an evaluation of the CAP’s applicability to the entity’s Protection Systems at other locations.” As it is presently handled, the entity can complete the CAP when the work at the place the misoperation took place is complete, and then the entity is responsible for its assessment/implementation at other locations (implementation of which may take a lot longer). However, the new standard needs to clearly state if this expectation is still the case, or if something different is now warranted. 2) Application Guidelines – Reporting section on page 20 states ‘…the fourth ranked initiating cause of BES outages not related to weather was “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.’ While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 3) All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. Suggest having a more general statement such as “A misoperation investigation report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation.” For example, if you find a piece of equipment failed (powered down), a sequence of events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a “may” and an “or” to the third sentence of page 18 “The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records.”
Individual
David Burke
Orange and Rockland Utilities
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
As a result of the new BES Definition (100 kV Bright-line), some new BES assets could be identified. The timeline proposed in R1, R2, and R3 in this Standard should not apply to the newly identified BES assets.
Group
Dominion
Louis Slade
NERC Compliance Policy
No
a). Under Definitions of Terms Used in the Standard, #3 indicates that delayed clearing of a high speed protection system is a Misoperation if it does not meet TPL requirements or coordination requirements. The specific requirements being referred to are unclear and non specific. Is the intent to report failure of high speed tripping for those Protection Systems that impact system stability? Suggest that more clarity be given to the requirement references. b). Under Definitions of Terms Used in the Standard, #5 change definition to read – Unnecessary Trip – During Fault – A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding properly coordinated remote trips when the local Protection System fails to clear the Fault. c). In the Application Guide – Guidelines and Technical Basis, under the definitions there appears to be more emphasis on Generation related examples. Recommend a balance of both Generation and Transmission examples in this guide.
Yes
No
a). R1 introduces a 120 day requirement in order for a correct and consistent review, and classification of, Misoperations. By introducing individual time requirements, this places unnecessary burden on entities to track dates associated with each phase of a Misoperation investigation and review. Dominion recommends an approach similar to that recently taken in COM 003, through the development of a requirement to have a process and plan in place to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and adding additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and date recording. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current language in the standard that includes 120 and 60 day requirements. Suggest using a 180 day overall time from the Misoperation date to finish one of these: 1)develop CAP, or 2)develop action plan or 3)develop declaration. Changes to the quarterly reporting template to remove and rename date fields will be needed and are included under question 5 comments. b). Revisions should be made to the Misoperations reporting template to capture requirements not currently covered in the template. For example, R2 introduces the option of a “declaration”. The template should include a feature to record a declaration. Entities should not be required to use multiple tracking tools or techniques to document the various requirements. One tool should exist to do this and currently all entities use the reporting template. c). All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report. d) R3 introduces an undefined term – an ”action plan” for those misoperations without an identified cause. There is a concern that entities will be confused with Corrective Action Plan and action plan terminology. Suggest changing R3 to read “For each Misoperation without an identified, the Registered Entity

cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the Misoperation, identify any additional investigative actions and/or Protection System modifications., including a work timetable, or document why no further investigation or actions will be taken.
No
a). Subpart 1.1 does not provide for a clear hand-off when another entity’s Protection System component contributed to a Misoperation of the first party. Specifically, it appears that the first party will have to develop its CAP to include a component owned by another entity and for which it has no control. The Application Guideline speaks to the need for various component owners to cooperate in the investigation and contact the Regional Entity should there be a lack of cooperation. This guidance needs to be clarified in the Requirement as compliance is measured against the Requirement, not guidance. Suggest adding Subpart 1.2 to state: “If notified by an entity that a Protection System component contributed to that entity’s Misoperation, than It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken.” If adopted by the SDT, then renumber existing Subparts 1.2 and 1.3 to 1.3 and 1.4 respectively. b). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the location of the Misoperation is agreed to by the various Protection System owners, then it should be the responsibility of the owner of the Protection System that misoperated to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different owners and the Protection System failure was due to a Protection System failure by an entity that had no devices that were interrupted at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. The process (especially reporting process and resubmittals) is simplified when the owner of the Protection System that misoperated is responsible for: interfacing with others to analyze, developing CAP, implementing CAP and reporting. c). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that had the Protection System Misoperation to initiate reports and communicate other entity actions.
No
a). Eliminate the field “Additional BES Interruptions”. This places unnecessary burden on entities to report interruptions that may not be associated with a Power System Misoperation. There is no need to track or collect this additional input. b). Instruction for Attachment 1 needs to include specific information as to when to fill out specific data in this field. The template currently requires a brief description in the Event Description field and details in the Corrective Action field when classified as Corrective Action in Progress. Once the Corrective Action Plan is completed, the instructions say to clear this field (which we disagree with) and input cause information under the Event Description field. Recommend renaming this field from Event Description/Analysi to Event Description. c). d). There should be a means to separate Generation and Transmission. This approach doesn’t appear to give entities the option of separating reports. e). Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. Provide examples how to separate settings from logic when it’s all part of a smart relay setting. f). Please split Communication Failure into two separate categories, one for ‘Power Line Carrier’ and one for ‘non-Carrier’ to improve the usefulness of the metrics regarding Protection System performance. g). Please eliminate the TADS and GADS information. TADS only counts lines and transformers that operate, not any other equipment. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. However the definition of an operation and rules for determining the number of operations will need some clarity. h). Drop the word “general” in the field name Misoperation General Cause”. No need to introduce another undefined descriptive word. i). Remove the following fields: ”Event Analysis Completion Date”, “Corrective Action Plan/Declaration Development Date”, and “Action Plan/Declaration Development Date”. j). Revise “Target Resolution Completion Date” to “Resolution Target Date”. k). Revise “Actual Resolution Completion Date” to “Resolution Completion Date”. l). Prevent entry of data into a field that was made not applicable by a previous field selection.
No

a). For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. b). By having specific 60 and 120 day requirements, this brings additional violation complexity to the process and is unnessary. As stated previously, use same approach as COM 003 and eliminate the daily requirements. c). VSLs will need to address when a Misoperation is caused by an entity having no equipment operations where initial analysis is by first party and remainder of requirements apply to second party. (See comments to Question 4)
No
(If requirements change, measures need to change also. See comments to Question 4)
No
a). Must include a specific plan of transitioning open investigations or CAPs to new standard requirements and reporting requirements. b). Specifically state when all other requirements are effective.
R2 introduces the idea of a CAP “that includes an evaluation of the CAP’s applicability to the entity’s Protections Systems at other locations”. R4 states “maintain detailed implementation records of CAP including dated information surrounding any revision(s) and completion”. With all this said, is the CAP complete once we evaluate “identify every location where a similar problem may exist” or is the CAP only complete when all locations are fixed? There is no need to log revision(s) to the CAP. Having a current CAP available at any point in time should be sufficient without tracking CAP changes. In the Rationale for R4 it states “fully implemented”. We interpret this to mean fully evaluated and not fully fixed at all other locations?
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Group
Nebraska Public Power District
Cole Brodine
Nebraska Public Power District
No
I recommend adding the underlined text to the misoperation definitions for items: Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection systems for a reasonable number of system contingencies. Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate for a reasonable number of system contingencies, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. Perhaps the number of contingencies should be a set number such as one so that for non standard system configurations where coordination may be lost. For example, such as multiple ground sources being out of service causing ground overcurrent miscoordination in part of the system.
Yes
No
For R1 there is 120 days to identify, review, designate, correspond with associated etitites and investigate a misoperation to determine the cause. For R2 there is 60 days to develop a CAP once a cause is determined. This seems somewhat confusing in it may cut in to the 4 month time frame for R1. Perhaps it would be better to just state that a corrective action plan shall be developed within 6 months as in R3. This would be 6 months to create a CAP as the maximum interval or declare why a CAP is not needed. This may also be easier to audit since documenting when the cause is determined

to start the time line would not be required. The VSL could then be updated and be simplified.
No
I have concerns with the requirement R1.1 and M1 related “demonstrating transmittal and receipt of information” such as saving correspondence or communications (notifications) with other entities as part of the analysis and corrective actions with this standard. The misoperation is identified and fixed (or not fixed) by means necessary for the involved entities following the other requirements. This requirement will add time burden for tracking communications that takes away from the goal to fix the issue. It also confuses the issue on who is responsible if a “receipt” of notification cannot be obtained. This would increase the difficulty for auditing as well and adds a subjective nature to what is considered acceptable correspondence. I recommend this part of R1 be removed or the proof that a transmitted notification was received by another entity not be required since that is not under the control of the sending entity. Also, rather than tracking numerous emails and notifications the option for lack of response is to appeal to the RE for help as stated in the application guidelines. It may be wise to have a contact/process at the RE assigned to follow up on these types of requests especially if the associated entity is not registerd.
No
Need clarification on these items: For Registered Entity ID#: What is the option to fill in the field if the portion of the protection system that misoperated is owned by a non registered entity? The fields Event Analysis Completion Date, Corrective Action Plan/Declaration Development Date, Action Plan/Declaration Development Date seem like they would not have much metric value and add extraneous information. These should be removed. For the Reported By, Phone Number, and E-mail Address line items is this the compliance contact # for a utility or a specific person writing the report? Using specific names, email, and phone numbers can create issues either way. Perhaps it would be best to use more general contact information for the entities or a single point of contact so these line items would stay more constant.
No
Other comments and concerns stated for R1.1 would need to be addressed and modified in the VSLs. The severe violation for failure to notifiy and provide requested investigative information should be removed. This will be difficult to audit and has a subjective nature. It also puts a burden on the sending utitilty where all aspects are not under their control especially if the receiver does not want to cooperate.
No
As mentioned above there are concerns with requirement R1.1 and M1. See comments for question 5.
Yes
It sounds like a CAP is a case by case document for each misoperation and does not need to be a formal CAP process document that explains the steps that will be followed for all misoperation investigations. Is this correct? I have concerns with the open ended nature of the statement in R2 “Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP’s applicability to the entity’s Protection Systems at other locations”. Specifically my concerns are with the last part referring to “at other locations”. I am curious how the STD would consider if a miscoordination resulting in a misoperation were to happen on their system. Would they consider reviewing the coordination for every relay at every substation on their system? This requirement has value yet also opens the door to unreasonable CAPs as well. This requirement also seems quite subjective in how it could be audited as well. Does the STD share this concern? Will the registration criteria or BES definition be referenced to set generation sizes for reporting misoperations? The application guidelines are verfy helpful in explaining the SDT expectations and should continue to be part of the standard for guideance.
Individual
Thomas Foreman
Lower Colorado River Authority
Agree
Lower Colorado River Authority Segment 1
Individual

Jim Cyrulewski
JDRJC Associates
Agree
Midwest ISO
Individual
Laurie Williams
Public Service Company of New Mexico
Yes
Yes
No
R1/R2: Regarding the proposed timeframes for completion of R1 and R2 as 120 days and 60 days respectively, PNMR suggests that the drafting team amend the requirements such that the combination of the two requirements not exceed 180 days, but allow for flexibility in either the analysis of the operation and/or the development of the CAP such that either one could be extended if needed but the entire timeframe allowed for both would not exceed the proposed timeframes as originally drafted. R1: PNMR proposes that an exception to the timeframe in R1 be allowed for complex failure to trip scenarios which are less frequent but can be difficult to recognize. PNMR requests that the time clock start from the time of discovery rather than the time of the operation. The requirement would instead read: “R1. Within 120 calendar days of discovery of an interrupting device operation in its Facility caused by a Protection System operation,…” Alternatively, PNMR suggests that there be an exception granted for certain failures to operate that are discovered after-the-fact.
Yes
Yes
Yes
Yes
Yes
R3 as drafted could be difficult to audit. PNMR suggests additional clarity be provided around what would be an acceptable criteria to invoke “A declaration explaining why no further actions will be taken.” As the standard is written now it appears that an RE could just declare a misop as having an unquantifiable cause and then declare that no further action is warranted or will be taken.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
The parenthetical at the end of the two "Failure to Trip" categories is not clear. Austin Energy requests the SDT to consider including some of the detail in the Guidelines and Technical Basis section on page 15 of the clean draft.
Yes
No
Given the length of the summer season in some parts of the country, Austin Energy requests an

adjustment to the time limits to sufficiently account for outage constraints for investigative purposes. AE requests that R1 allow for 180 calendar days and R3 allow for 240 calendar days. (These comments are similar to those submitted by Seattle City Light which, due to the length of the winter season in their part of the world, they also requested a longer period).
Yes
Yes
Yes
No
The phrase “must include” in measure 4 should likely be “may include.”
Yes
In the Applicability text box, the following phrase “of the automation portion” should likely be “or the automation portion.”
Individual
Don Jones
Texas Reliability Entity
No
(1) Failure to Trip During Fault: The statement “(The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.) “ is somewhat vague and open to interpretation. We understand the purpose of this language as stated in the Guidelines and Technical Basis, i.e. when a high speed zone element trips faster than a high speed pilot system. However, we have had instances in our Region where a high speed pilot system fails and the fault is subsequently cleared by a time-delayed zone element, typically in 30-45 cycles rather than in 5 cycles or less. This instance could be interpreted as “correct overall performance” by the entity and not reportable. Is this the intent of the SDT? Or should this instance be recorded as a “Failure to Trip” or “Slow Trip During Fault”? The Guidelines and Technical Basis section offers some good examples, however, it should possibly be expanded to provide more discrete cases. (2) Failure to Trip Other than Fault: See comments under Failure to Trip During Fault (3) Slow Trip During Fault: See comments under Failure to Trip During Fault
No
(1) It is not clear who is responsible for compliance with R1. Who must “identify and review”, “designate” and “investigate”? Is it the owner of the interrupting device that operated, or is it the owner of a component that caused or contributed to the Misoperation? This will be difficult to enforce without clearly assigning responsibility. (2) The requirement and the VSL assume that there are two steps in identifying a Misoperation: “determining” that an operation is a Misoperation, and then “designating” the operation as a Misoperation. There is no requirement that an entity diligently and correctly “determine” that a Misoperation occurred during its review of an operation, and there is no VSL that applies when an entity incorrectly fails to “determine” that a Misoperation occurred.
Yes
We generally agree with the deadlines, but we have questions about how they apply in a multi-party situation. If a Protection System Misoperation is determined and an entity (“Entity A”) determines that the cause of the Misoperation is due to a component owned by another entity (Entity B”), how does the 120 day time period apply? What if Entity A does not start its review until 60 days after the operation and tells Entity B on the 90th day? Entity A has identified the cause (Entity B component) but what timeframe is Entity B under to determine the Misoperation cause for the component? What exactly is Entity A’s mandatory obligation, and what is Entity B’s mandatory obligation, and what are the applicable deadlines?
No
(1) We voted “no” on this draft because it is unclear who is responsible for various actions in multi-

owner situations. The requirements need to clearly state who is responsible for compliance with each step of the identification, investigation, correction and reporting process. (2) We suggest that the team consider a solution such as: (a) the owner of the interrupting device should be required to identify the Misoperation and the suspected component that caused it, and then (b) the owner of the suspected component should be required to take the further steps to investigate and correct the problem and to submit the required reports. (3) Additional language is needed to clarify that, for Misoperation investigation and reporting purposes, the entity that owns the component that misoperated is required to submit the reports. Also, any CAP's should include the review of coordination issues between entities involved in the Misoperation.
No
(1) Is Attachment 1 considered to be part of the Standard? If so, then future modifications to Attachment 1 would have to go through through the SDT process and would entail extensive time and effort to make. (2) Under current practice, in many cases there is insufficient detail provided by the entities involved in a Misoperation to understand the root cause. There has been some discussion with the Protection System Misoperation Task Force (PSMTF) that additional data would be helpful in categorizing misoperations. In particular, it would be helpful to add subcategories below the misoperation general cause codes (i.e. Incorrect settings/logic design could have subcategories such as modeling errors, calculation errors, etc.). (3) The Periodic Data Submittal requirements and the template should be flexible enough to permit Regional Entities to collect additional information which may be beyond the scope of the PRC-004 Standard, if deemed necessary based on regional needs. For example, in ERCOT, the current regional rules for misoperation reporting also include failure to reclose, reporting the generator trips < 100kV, sudden pressure relay misoperations, SPS misoperations based on a regional definition, etc. These are included in the current template to streamline the reporting process for the Registered Entities, rather than requiring multiple reports. Since this information is outside the PRC-004 applicability, it is removed from the quarterly Misoperation reports by Texas RE before data is submitted to NERC. The previous draft of PRC-004-3 had flexibility in the periodic data submission language to allow this ("using the format specified by the ERO"), but that language was removed in the current draft.
Yes
We generally agree, however the Severe VSL for R1 includes "and failed to notify and provide requested investigative information" but it doesn't address the situation where the entity provided notification, but failed to provide "requested investigative information." Also, the R1 VSL is overly complicated, perhaps showing that there are too many different elements in R1.
(1) R2 assumes that one or more "Protection System component(s)" has previously been "identified", but there is no preceding requirement that requires any such identification of components. R2 seems to infer that it is the owner of the component that caused the Misoperation who must act, but it is not expressly stated who is responsible for this requirement. (2) We agree with the approach of R2, however, we would suggest the following changes to wording to clarify this requirement by requiring certain elements in each Corrective Action Plan: R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, each applicable Entity shall: • Develop and document a Corrective Action Plan (CAP) and work timetable to resolve the cause(s) of the Misoperation that includes the following: 1. Interim corrective actions (if any), 2. Final corrective actions, 3. An evaluation of the CAP's applicability to the entity's Protection Systems at other Facilities, 4. An evaluation of the CAP's applicability to Protection System component(s) owned by another Registered Entity (if applicable for the specific event), or • Explain in a declaration why corrective actions are either beyond the entity's control, applicable to another Registered Entity, or would reduce BES reliability. (3) In R4: Implementation of the CAP should include a time limit. We suggest re-wording R4.1 to say "Implement the CAP or action plan within 180 calendar days after developing the CAP or action plan, or per the CAP or action plan timetable, whichever is longer."
Individual
d mason
HHWP
Agree
NAGF I wanted to provide additional comment related to the implementation plan and was unable to

undue the "Agree" radio button We believe that the six-month implementation timeline is insufficient for many small entities to revise existing misoperations identification and analysis procedures and provide appropriate training to relevant staff. We also would like to see all implementation plans include training key Standard requirements or changes, and CEA expectations for basic compliance.
Group
Luminant
Brenda Hampton
Luminant Energy Company LLC
No
Misoperations categorized in line items #3 and #4 are subjective and left up to varying interpretation for protective systems on generator applications. Unlike the definition for “Slow Trip – During Fault”, Transmission Owners are provided with criteria that define a slow operation while generation owners do not have similar established criteria for trips involved in items #3 or #4. Luminant recommends line item #4 be removed since it is subject to varying interpretations and item #3 be only applicable to Transmission.
Yes
Luminant agrees with the approach but suggests the following improvements to R1 and sub-requirements. 1) R1 should address the interrupting device as a “BES” interrupting device. 2) Luminant recommends that the concept of ownership be continued from the main requirement to each sub-requirement. For example, in 1.1, it would be written as follows: “Identify and review each of its applicable Protection System operations.”
No
The time frames and activities in R1-R3 are confusing and can be simplified. Luminant suggests that R1, 2, 3 be revised to allow owners 180 days from the time of the BES interrupting device operation to investigate, determine the cause, and develop a CAP (cause known) or action plan (cause unknown). An action plan can result in identifying a cause and should include a CAP. If a cause cannot be determined, the investigation is closed. Below is our recommendation for R1-R3: R1. Within 180 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, the applicable Transmission Owner, Generator Owner, and Distribution provider shall: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning] 1.1 Identify and review each of its applicable Protection System operations. 1.2 For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System. 1.3 Identify each of its Protection System misoperations, determine a cause (if known), and develop a Corrective Action Plan (CAP). R2. For misoperations where the cause cannot be determined within 180 days of the BES interrupting device operation, the applicable Transmission Owner, Generator Owner, and Distribution Provider shall develop an action plan to: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning] o Develop a CAP within 60 days after identifying the cause of the misoperation for the Protection System component(s). o Where applicable, explain in a declaration why corrective actions are beyond the entity’s control or would reduce BES reliability and close the investigation. R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall implement its CAP according to the established timetable. [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning].
No
Luminant disagrees with the concept of “If an entity suspects …” phrase. Luminant suggests that the data exchange between entities with “interpendent System protection Systems” be as follows: “…For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System.” The owner of other components in the Protection System may request information in performing their investigation.
No
The data provided by the quarterly report would have little, if any, reliability benefit to the BES due to the limited technical information provided in the Attachment. Luminant recommends that a report be provided on an annual basis.
No

Change accordingly to the response to Q2 and Q3.
No
Measure M1 should not be written to include “all interrupting device operations must be logged”. Luminant recommends that the measure for Part 1.1 be revised from “each interrupting device” to “each applicable interrupting device”. M1 measures for part 1.2 and 1.3 would be “Acceptable evidence for Part 1.2 may include, but is not limited to, electronic or written documents that indicate the owner of was notified of the event associated with the operation. Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of a dated investigation report or documented findings for Misoperation.”
Yes
Luminant does not agree with Requirement R3 of the standard since there is an apparent conflict or double jeopardy with the draft standard on generator relay loadability (PRC-025-1). Luminant recommends that R3 of PRC-025-2 be removed and any event from a generator load responsive relay for review be in the draft PRC-004 standard that operates an interrupting device. The chairmen of both SDT’s should consult with one another to remove any conflicts.
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Yes
Yes
No
UI does not agree with including any of the reporting process in the PRC-004 standard or its attachments. The information to report does not require Ballot Body Approval initially or each time a field is to be modified.
Yes
Yes
No
The implementation plan should recognize that the Requirements will be applied to the first protection system operation that occurs AFTER the effective dates. Any operations or misoperations or corrective action plans being implemented are not subject to this Standard.
R2 should not specify that the CAP contains an activity to evaluate applicability to all of the entity’s Protection System. It could create a situation where check-sheets are required with sign-offs for review of all systems. R4.2 is of concern with the requirement to maintain detail implementation records of each CAP or action plan. Detail is an ambiguous word that can not be complied to. The compliance burden to provide detailed implementation records is excessive. A Transmision Owner is audited every 6 years. A TO will need to provide detailed records of CAP’s and action plans for 6 years. The only organization receiving a benefit from this requirement is the NERC Audit team. All that should be required by the Standard is the date of completion on the CAP implementation. Additionally, There should be no requirement to record revisions to the CAP.
Group
PacifiCorp
Ryan Millard
PacifiCorp

Yes
Yes
No
PacifiCorp is concerned that the 120-day time limit in R1 is insufficient. When two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase to 90 days for each entity to complete their respective activities in sequence. This would increase the total from 120 to 180 days under R1.
No
See comment #3
No
PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a “Lower” and a “Severe” VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional 30 days late should not increase the VSL from “Lower” to “Severe.” A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity’s failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days.
Yes
Individual
Ed O'Brien
Modesto Irrigation District
Yes
Yes
No
Standardize a single time frame for evaluation and remidiation. Keep it simple. Also recommend longer time period for completion of remidiation, such as 240 days.
Yes
No
Resolution Status has too many options. Keep it simple. Suggest 1) Evaluation underway, 2) Evaluation Completed, Remediation activity begun, 3) Remediation activity complete.
No
VSL levels should comport with the amount of errors/missed completions discovered, not time delay for a single missed completion.
Yes
Yes
Concept of standard is generally very good. Please remember to keep overall reliability goals in mind, and not have entities (especially small ones like ours) get bogged down in paper-trail activities.

Individual
Martin Bauer
US Bureau of Reclamation
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Including the TADS information provided under the NERC Rules of Procedure is in conflict with this standard. TADS' reporting is on an annual basis. By including the TADS event ID, the standard would require quarterly reporting of the TADs event. The inclusion introduces the conflict between the rules of procedure and a standard. Including the quarterly reporting as part of the compliance information is not consistent with standard requirements. There is requirement VRF or VSL assigned to the reporting and therefore no compliance violation can be assessed for failure to respond. The reporting information is not subject to a requirement per Commission guidance since it is only for metrics and administrative purposes per the SDT. The information collected under this standard is inconsistent with the information collected for Transmission system events. TADs event data is collected under the NERC Rules of Procedures. The standard should be modified to remove the reference to the additional compliance information and have the information collected under the NERC Rules of Procedures.
Individual
Christina Koncz
PSEG
Yes
No
We have divided R1 into two requirements (R1 and R2) below to clarify what occurs when a Misoperation occurs on a Protection System component owned by one entity and that Misoperation causes another entity's interrupting device to operate. Under the new R1 below, the interrupting device owner must first determine, within 90 days, if a Misoperation occurred and whose Protection System component was responsible. If another entity is responsible, that entity is notified. Under R2, the entity whose Protection System component misoperated must do the completed a Misoperation analysis within 210 days of when the Misoperation was identified. See below: R1. Within 90 calendar days of an interrupting device operation in its Facility, each Transmission Owner, Generator Owner, and Distribution Provider shall determine if its Protection System (a) operated properly, or (b) had a Misoperation, or (c) operated properly with indications that Protection System component(s) owned by another entity had a Protection System malfunction that caused the interrupting device operation and, if applicable, shall complete part 1.1. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] o If condition (b) is the findings, the interrupting device owner shall be responsible for the investigation in Requirement R2. o If condition (c) is the findings, the

other Protection System owner shall be responsible for the investigation in Requirement R2. 1.1 For a condition (c) finding, the interrupting device owner shall notify the owner of that Protection System component(s) and provide any available investigative information that is requested by that owner in writing. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning.] o In the event that the owner of the interrupting device and the owner of the other Protection System component(s) disagree on the interrupting device owner's determination in R1, the Regional Entity shall investigate and make a determination as to which entity is responsible for the investigation in Requirement R2, and the identification of a Misoperation will be considered completed when Regional Entity's decision is rendered. M1. For R1, each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence of the date of the interruption device operation and the date it completed its review of each interrupting device operation, including its associated determinations. Evidence for Part 1.1 includes documentation of written transmittals to the other Protection System owner (notifications and requested information) including, but not limited to, transmittal e-mails, log entries, or letters. R2. Within 210 calendar days after identifying a Misoperation per R1, the responsible Transmission Owner, Generator Owner, and Distribution Provider shall complete an investigation report of each Misoperation that state the Misoperation category and cause. If no cause is determined, the report shall state that. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] M2. Acceptable evidence for Requirement R2 may include, but is not limited to, a copy of a dated investigation report with documented findings for each Misoperation, including a description of the equipment involved in the Misoperation.
No
In addition to the new R1 and R2 above, R3 through R4 below are an alternative to replace the proposed R1 through R3. R3. If the cause(s) for a Misoperation is identified in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 days of identifying a Misoperation per R1: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or o Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP. R4. If the cause for a Misoperation is undetermined in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 calendar days of identifying a Misoperation per R1, complete: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including an estimated timetable, or o A declaration explaining why no further actions will be taken. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R5 that must include a dated action plan or a dated declaration explaining why no further action will be taken.
No
We believe that our alternative language in #2 and #3 above is clearer. In addition, a Misoperation analysis is required even when a cause cannot be determined. After that analysis is completed, an entity either develops a CAP or an action plan.
Yes
Metrics can be developed, but the team should describe what metrics it envisions and how those metric will be used.
We did not focus on the VRFs and VSLs and have no comments
No
We have proposed alternative Measures in #2 and #3 above and in #9 below. The Data Retention language is acceptable.
Yes
No comments.
We have provided new language below that continues after our R4 above. R5 addresses implementation of the CAP or action plan. R6 requires reporting of data in Attachment 1. We believe that providing the data in Attachment 1 should be a requirement instead of being addressed in the "Additional Compliance Information" section. R5. For each CAP or action plan, the Transmission

Owner, Generator Owner, and Distribution Provider shall implement the CAP or action plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning] M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R5 that includes dated records which document the implementation of each CAP and action plan, such as work orders or maintenance records that document the completion of work or maintenance, including documentation of revisions for each CAP or action plan. R6. Each Transmission Owner, Generator Owner, or Distribution Provider shall submit PRC-004 – Attachment 1 to its Regional Entity within two calendar months following the end of each calendar quarter. [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Long-Term Planning] M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R6 that it transmitted PRC-004-3 – Attachment 1 to its Regional Entities within two calendar months following the end of each calendar quarter. We have also addressed the “Facilities” portion of the standard in the “Applicability” section and suggest the language below, parts of which were taken from PRC-005-2. The Protection Systems in 4.2.1 and 4.2.2 provide protective functions. Section 4.2.3.3 excludes UFLS systems whose operation is evaluated in PRC-009-0. While it is clear that the team wanted to exclude relays such as reveres power relays for generators, their description of these as providing “non-protective functions” is inaccurate since they prevent a generator from motoring during shutdown. They protect the generator. We have excluded those applications in our Section 4.2.3.4 because the operation of an interrupting device caused by a reverse power relay is associated with a normal generator shutdown. The Misoperation of such a relay results in the motoring of a generator, and while that can create a serious problem for a Generator Owner who is incented to evaluate such Misoperations absent a standard, it does not create a BES reliability issue. 4.2. Facilities 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) or abnormal conditions. 4.2.2 Protection Systems for generator Facilities that are part of the BES for the purpose of detecting faults or abnormal conditions, including: 4.2.2.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. 4.2.2.2 Protection Systems for generator step-up transformers for generators that are part of the BES. 4.2.2.3 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). 4.2.2.4 Protection Systems 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. 4.2.3 Facilities not included 4.2.3.1 Special Protection Systems (SPS) or Remedial Action Schemes (RAS) 4.2.3.2 Undervoltage load shedding (UVLS) systems 4.2.3.3 Underfrequency load shedding (UFLS) systems 4.2.3.4 Relays that operate for the normal shutdown of an Element. Finally, we believe in the Application Guideline, the third sentence in the first paragrqaph on p. 18 of 22 is written too restrictley. We suggest this language instead: The initial evidence, which may also be documented separately, MAY CONTAIN [delete “contains.”] the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records, TO THE EXTENT AVAILABLE.
Individual
Daniel Duff
Liberty Electric Power LLC
No
The "unnecessary trip- other than fault" should be removed. Standards should not cover balance of plant issues, which could be trip causes. While trip analysis is a best practice, it should not be a required, zero tolerance element of the NERC standards. For example, a turbine vibration fault could use the same 86 relay as the generator protection relay, which would make that 86 part of the protection system. Vibration trips of that 86 relay would then fall under the program, causing unneeded effort for compliance documentation of a straightforward balance of plant issue. The definitions themselves are overly complex, and could be combined in many cases.
No
See comments in Q1. In addition, the standard needs to specifically exclude reverse power relay activations from misoperations analysis, as these activations are a normal event in the shutdown of many units.
Yes

Yes
No
Limit resolution status to "work in progress" and "complete". Forms are too complex, with many elements not used by generator operators (example:TADS), or not known by GOPs ("Other BED elements", etc.)
No
Suggest removing R4 lower - too subjective.
No
Disagree with the requirement for "each interrupting device activation" list - some activations are normal shutdown activations.
Yes
Individual
Andrew Z.Pusztai
American Transmission Company
Agree
ATC endorces and agrees with comments submitted by the MRO NSRF.
Group
SERC Protection and Control Subcommittee (PCS)
Joe Spencer
SERC Reliability Corporation
Yes
No
1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "…such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. 2) Clarify the Rationale consistent with Technical Basis page 17, by clearly stating that "the interrupting device owner is responsible to investigate operations initiated by a Protection System." 3) Augment the Rationale by adding at the end, "…and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information." A fair number of Misoperations trip another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but, once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction. 4) Change R1 1.2 to "Designate each operation as correct or a Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps." IEEE 1366 defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.
No
1. SERC objects to the timetables and the compliance burden it places on entities: There is no evidence or indication that entities are not doing due diligence in reviewing operations. Quarterly reporting schedules help drives closure. 2. R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity's Protection System components misoperated (i.e. Other entity

sends a spurious DTT), then, once the cause of the Misoperation is determined, it should be the responsibility of the owner of the Protection System that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. 3. R1 introduces a 120 day requirement for performing a correct and consistent review and classification of Misoperations. By introducing individual time requirements, this places an unnecessary burden on entities to track and document each phase of investigation and review of a Misoperation. Similar to the approach taken in COM 003 recently which included a requirement to have a process and plan to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and to add additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and documentation. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current verbiage in the standard referencing the 120 and 60 day requirements. 4. All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report.
No
1. Please refer to comments in #2 above (SERC comments 2 and 3). Also, consider the following: a). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity’s Protection System components misoperated (i.e. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, it should be the responsibility of the Protection System owner that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
No
1) Please change ‘Time Zone’ Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for ‘Carrier’ and one for ‘non-Carrier’ to improve the usefulness of the metrics regarding Protection System performance. 4) Please eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. The SERC PCS recommends that the rules for determining an “operation” be consistent between TADS and PRC-004 reporting. Also need to coalesce data systems (GADS, TADS , PRC-004, etc.)
No
While the SERC PCS does not see the need for timetables (see comment under #3), if they are put in place, we offer the following recommendations: 1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison, R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. 2) R2 VRF measures duration from ‘completion of the investigation or receiving notification’ but R2 itself measures from ‘identifying the cause(s) of each Misoperation’. Please change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.
Yes
1) Please clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the

last audit.
Yes
Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as ‘Update’ Submittal Type once it becomes effective?
1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP “includes an evaluation of the CAP’s applicability to the entity’s Protection Systems at other locations.” It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period. 2) Please reword C.1.4 from “Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA…” to “For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA…” This clarifies who is responsible for submitting when multiple entities are involved. 3) Application Guidelines – Reporting section on page 20 states ‘…the fourth ranked initiating cause of BES outages not related to weather was “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.’ While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 4) A significant effort has been expended in developing the current PRC-004 misoperations template. The SERC PCS recommends that the SDT leverage this effort in consideration of misoperations reporting (Atta 1). 5) The SERC PCS recommends that the application guidelines be used for assessing misoperations and not for operations. 6) All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. Suggest having a more general statement such as “A misoperation investigation report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation.” For example, if you find a piece of equipment failed (powered down), a sequence of events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a “may” and an “or” to the third sentence of page 18 “The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records.”
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Entergy is concerned with the lack of definition surrounding the statement "review each Protection System operation" in R1.
Individual

Clay Young
South Carolina Electric and Gas
Agree
SERC PCS
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
ACES Power Marketing
Yes
The definition and its rationale seem reasonable. One observation is to shorten the language of each category of Misoperations. Generally, detailed definitions cause more problems in compliance than short and concise definitions. We had one question for the SDT regarding the definition – is breaker failure considered a Misoperation?
No
There is not a NERC glossary term for “interrupting device.” The SDT should consider proposing a new glossary term to clarify what Protection System equipment is included in order to properly analyze all applicable equipment. Does the SDT intend interrupting devices to include switching equipment capable of interrupting a fault or would the team also include switching equipment capable of interrupting load? This term could include more than is intended and additional clarity is needed.
No
The SDT should consider providing an exception process if there are unforeseen delays that inhibit an investigation to occur within 120 days. For instance, there could be difficulties with coordination for multiple interrupting device owners. There are numerous reasons that could cause a delay to go beyond the 120 days, so there should be some sort of time allowance to provide extra time if the excuse is justified and reasonable.
No
(1) There is no justification in the Rationale for R1 or in the Application Guidelines to show statistics that this scenario would occur regularly. The supplemental documents do not explain why the SDT felt that adding this provision to the standard was necessary. This concept seems to be a rare instance without a basis for adding it as a requirement. Considering that this requirement is on a timeline for which compliance would be measured. (2) The requirement’s wording is subjective in nature and would be very difficult to provide documentation for “suspecting” another entity’s component contributed to the Misoperation. Also, R1.1 seems to skip a step – first the entity identifies and reviews all operations but the next step should be to identify Misoperations. Once Misoperations are identified, then the investigation for the cause of the Misoperation would occur. The investigation step is when an entity would consider if another entity’s components or equipment would have been the cause to the Misoperation. Therefore, we recommend striking the second sentence of 1.1.
Yes
No
(1) We agree with the classification of the VRFs. (2) The time horizons for R2, R3, and R4 are Long-term Planning, which is a planning horizon of one year or longer. There is a gap in the time horizons – the 180 day mark is longer than seasonal but shorter than 1 year. We recommend classifying these standards as Operations Planning, which would be consistent with R1. (3) The violation severity level for R1 increases based on arbitrary timelines. It is conceivable that an entity could identify and review a Misoperation on day 150 (which would be a severe VSL) and complete the CAP 20 days after, which would still be within the 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and if an entity did not do anything that would be a reasonable justification for severe. (4) Also in R1 VSL, the second paragraph in the Lower section is almost identical to the second paragraph in severe, which is confusing and could lead to inconsistent application. We recommend revising the R1 VSLs for clarity and would like the SDT to consider creating VSLs that determine the severity level if R1 and R2 are not completed in a certain

period of time. (5) Our concerns with the R2 VSL are similar to paragraph (3) above. It is conceivable that an entity could identify and review a Misoperation on day 30 and complete the CAP 70 days after (which would be a severe VSL), and would still be well within the total 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and not doing anything would be a reasonable justification for severe.
No
The SDT referenced NERC Rules of Procedure, Appendix 4C (CMEP), Section 3.1.4.2 Period Covered for compliance data retention to begin with the day after the prior Compliance Audit and ending with the End Date for the Compliance Audit. However, the SDT did not include the final two sentences in Section 3.1.4.2, which states: "However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means." Six years is excessive to maintain records for Corrective Action Plans. The SDT is within the bounds of the NERC Rules of Procedure to shorten that amount of time. We recommend three years for data retention for Correction Action Plans.
Yes
Why is UFLS not excluded when UVLS is? Also, are registered entities required to perform the 120-day assessment at least once before the enforceable date? Please refer to CAN-0012, which provides that if the standard is silent to performing a periodic activity, the entity can perform the first activity after the enforceable date.
(1) There is ambiguity in R4, part 4.2, “maintaining detailed implementation records,” which could be interpreted in different ways by auditors as to the degree of detail that is needed for implementation records. The measures give examples of acceptable methods to achieve compliance and therefore we recommend striking the word “detailed” from part 4.2. Further 4.2 is strictly a data retention requirement, which is administrative in nature and should be removed. This is the type of requirement that Paragraph 81 is currently in the process of retiring. (2) In part 4.2.3 of the applicability section, the SDT needs to emphasize that relay functions are not included in the definition of Protection Systems. By explicitly stating that certain non-protective functions that may be embedded within a Protection System are excluded, it could be interpreted that anything else that was not explicitly mentioned in the requirement could be included, such as sudden pressure relays. We recommend adding additional detail to this section for clarity. (3) Does the SDT intend to remove the old definition of Misoperations from the background section? It does not need to remain as supplemental information with the passing of the new definition. We understand that certain aspects of the standard would be removed, such as the rationale boxes, but there is no mention that background section would be removed. (4) In the application guideline, Requirement R3 section, first paragraph first sentence – “If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation.” This sentence needs to clarify what reasonable means. It appears from this statement that if you did not exhaust all reasonable investigations, then you should continue additional investigations, but at that point, you would be in violation of R1. The SDT needs to consider rewording this sentence, possibly striking the underlined portion of the sentence. (5) In the application guideline, Requirement R4 section, second paragraph – this paragraph is discussing the goals of R3 and we recommend moving this paragraph to the R3 section. Thank you for the opportunity to comment.
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
Yes

No
In regards to R2, the 60-day period for developing a CAP seems to be reasonable; however, this period starts from the date the cause of Misoperation is identified. “Date of cause” could be subjective and can potentially generate confusion and unnecessary violations. LADWP recommends using the date of “device interruption operation” and change “60 days” to “180 days.”
Yes
Yes
Yes
Yes
Yes
Group
Colorado Springs Utilities
Jennifer Eckels
Colorado Springs Utilities
Yes
No
The way R1 currently reads, investigations would be required for planned work (e.g., full function trip testing). Language should be “Within 120 calendar days of an unplanned interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall:”. The “unplanned” should apply to the interrupting device operation, vice Protection System operation, so that an investigation is required for misoperations during testing.
Yes
Yes
No
Attachment 1 does not describe data that is appropriate for metric analysis for a couple reasons: (1) This standard applies to both Generation Owners (GOs) and Transmission Owners (TOs); however, GOs are not in a position to respond to the last item on page 1, "Additional BES Interruptions." GOs are responsible for BES equipment in their plants and are not responsible for BES equipment belonging to TOs. Therefore, GOs should not be responsible for determining any BES interruptions outside of the plants. We recommend removing the section, “Additional BES Interruptions”. (2) If TADS/GADS data is required for metric analysis, then an explanation should be provided for why the data is required. We recommend that NERC or the Regional Entity provide an explanation for the relevance of the TADS/GADS data to the metric analysis.
Yes
Yes
Yes
We understand that this was an arduous standard to develop, and it required extensive explanations for requirements and measurements. We agree with the concepts presented in PRC-004-3, and we

believe it was very well-written. We appreciate the effort that went into developing and reviewing this revision. However, frequent revisions of standards, coupled with frequent revisions of definitions, do not help to maintain consistent procedures for ensuring the reliability of our protection systems. We suggest that national standards only require what is deemed absolutely necessary on a national level. Any further requirements and recommendations should be provided by Regional Entities. This will mitigate misinterpretations of the standard and lessen the amount of revisions to the standard.
Individual
J. S. Stonecipher, PE
City of Jacksonville Beach, FL dba/ Beaches Energy Services
No
The description of "unnecessary trip", the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not "unnecessary") and it is intended to operate for failure or slow operation of Local Protection Systems. The description for a remote back-up system operation and limiting that to only the "adjacent" zone is not appropriate. There are cases when the appropriate protection system operation may not be from the "adjacent" zone of protection. Also, the term "zone of protection" is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different "zones of protection". If a zone 3 relay covers two transmission facilities, is that one and the same "zone of protection"? Or does the SDT intend a zone to be breaker-to-breaker? How is a Circuit Switcher treated when defining a zone of protection>? Etc. The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
No
The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. We are, not in favor of a zero defect approach, especially when most relay operations operate correctly. We recommend using approaches similar to what the COM-003 and CIP v5 teams are considering. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection system operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was "slow" or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence? It would seem to us that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
No
We believe there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
(No Comment.)
(No Comment.)
(No Comment.)
(No Comment.)
(No Comment.)
Applicability of 4.2.1 "Protection Systems for Facilities that are part of the BES" is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. We recommend using the FERC approved interpretation of PRC-004-1 Attachment 1. R3 is not needed, is administrative in nature, and provides no reliability benefit. R2 should be modified to be applicable only to misoperations where cause(s) were identified. R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted.
Individual

Eric Salsbury
Consumers Energy
No
Protection Systems can be and are designed to provide remote backup protection for adjacent zones. In many instances, these zones are owned and operated by other entities. As worded, part 1 of the definition says “failure…to operate for a Fault within the zone it is designed to protect.” If entity A has a Protection System that is designed to provide remote backup protection for entity B and entity B has a Fault on that Element, but does not notify entity A of said Fault, then without an interrupting device operation, entity A has no way of knowing if their Protection System should have operated or not. Proposed solution: Failure to Trip – During Fault – A failure of a Protection System to operate for a Fault within the zone it is designed to be the primary protection.
Yes
Yes
No
R1.1 seems to be intending that the owner of the interrupting device perform the intial investigation. If a Misoperation is identified and the Protection System is owned by another entity, the wording of the standard is not clear about which entity should be responsible for the CAP, etc. The rationale paragraph covers this, but of course won’t be included once the standard is finalized. Are both entities responsible for documenting the operation/Misoperation?
Yes
Yes
Yes
Yes
The quarterly reporting of Misoperations provides no benefit to the reliability of the Bulk Electric System and the entities are required to spend additional resources to develop these quarterly reports instead of focusing on the actual reliable operation of the BES. Performance metrics can be determined on a yearly basis, through annual reporting.
Individual
Mike Hirst
Cogentrix Energy, LLC
No
The proposed definitions are unneccisarily complicated. Also, the "catch all" category "Unnecessary Tip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out.
Yes
The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor. This form of protection is more "visible" during a normal stop event, but a reverse power

relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitely stated that reverse power trips during a normal stop event be not considered as Misoperations. It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop (ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section). The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO’s standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to function.
Yes
Yes
No
There are too many classification choices in the “Resolution Status” field of the report form. An equally effective status report can be delivered using three choices: 1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed – Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] The form for GOs should differ from that for TOs, for the following reasons: a. GOs are not in a position to respond to the last item on p.1, “Additional BES Interruptions.” We know only what happens in our plants, not repercussions on the grid. b. The “slow trip” entries in the “Misoperations Category” do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker – that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). Additionally, there is no reference to reporting in a manner outlined by the CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
No
Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
No
M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents

should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Yes
Compliance section C1.4 contains a requirement to report to the RE – this needs to be in the requirement section of the standard.
Group
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
No
The description of "unnecessary trip", the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not "unnecessary") and it is intended to operate for failure or slow operation of local Protection Systems. The description for a remote back-up system operation and limimting that to only the "adjacent" zone is not appropriate. There are cases when the appropriate protection system operation may not be from the "adjacent" zone of protection. Also, the term "zone of protection" is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different "zones of protection". If a zone 3 relay covers two transmission facilities, is that one and the same "zone of protection"? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc. The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
No
The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. FMPA is not in favor of a zero defect approach especially when most relay operations operate correctly. FMPA recommends usin g approaches similar to what the COM-003 and CIP v5 teams are considering. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was "slow" or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence? It would seem to FMPA that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
No
FMPA believes there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Applicability of 4.2.1 "Protection Systems for Facilities that are part of the BES" is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. FMAP recommends using the FERC approved interpretation of PRC-004-1 Attachment 1. R3 is not needed, is administrative in nature, and provides no reliability benefit. R2 should be modified to be applicable only to misoperations where cause(s) were identified. R4.2 is administrative in nature, is a Measure,

not a requirement, and should be deleted.
Group
Western Area Power Administration
Brandy A. Dunn
Western Area Power Administration (Corporate Services Office)
Yes
The Applications Guidelines section of the proposed standard is invaluable in clarifying the requirements. We propose that some of this information be directly added to the associated standards. This includes statements in items (2) and (6).
Yes
While an entity can transmit information regarding a possible misoperation to another entity, the initiating entity cannot force a response. An entity which receives a transmittal is responsible for a response.
Yes
Yes
An entity cannot be held responsible for another entity's failure to respond or act upon notice of a suspected misoperation.
Yes
No
The metrics seem arbitrary and not linked to possible risk to the BES.
Yes
Yes
We agree that these are good business practices and, in fact, we are currently performing these practices already. However, we have a great deal of concern that the documentation burden required to meet compliance continues to increase exponentially. We would like to point out that the current documentation requirements are diverting a significant portion of our resources away from system improvements. Please add the following items (found in the Applications Guidelines) directly into the standard requirements: • Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems. • An unintended operation as a result of on-site maintenance, testing, construction or commissioning is not a Misoperation. • In some cases, where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. • Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
PPL Generation, LLC on behalf of its Supply NERC Registered Entities
Yes
No
The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. The SDT evidently meant to prevent this circumstance from posing an unwarranted

burden by stating in the Application Guidelines that, “...in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.” The line of demarcation between the protection and control functions of reverse power relays is not at all clear, however. We typically have for example a primary reverse power relay that trips the breaker 3 seconds after detection of motoring if all MS and HRH valves are indicating closed, and 27 seconds later regardless of valve position if it is not already offline, plus a backup relay that acts one minute after the start of motoring regardless of valve position. We take the 3-sec action as being a control function, while the other timers are protective in nature. What they protect is the low-pressure turbines from windage (high temperature) damage, however, not the generator. The reverse power function is consequently in the same class as a low lube oil pressure switch, and should not be in the scope of Protection Systems. PRC-004-3 as presently written though appears to require analysis of every reverse power trip that is not caused by the 3-second function described above, which may occur quite often given that valve position indicators are not high-reliability instruments. Each such investigation would involve documenting the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop (ref. the "Requirement R1" section of the Application Guidelines) and determining whether or not the Protection System operation was slower than expected (ref. items 2 and 3 in the "Guidelines and Technical Basis" section). The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO’s standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (inappropriately, we believe) as being part of the Protection System, but these devices do not trip in response to something having gone wrong, nor do they protect the generator. It is intended that negative current be experienced at some point as the unit unloads; and subsequent actuation of the reverse power relay is normal, expected and a mechanical (turbine) protection function. Requirement R1 and to the Application Guidelines should be modified to state that investigation of reverse power relay events is not part of the Protection System and PRC-004-3 consequently does not apply to such devices or, alternatively, is required only if the relay failed to function.
Yes
Yes
No
a. GOs are not in a position to respond to the last item on p.1, “Additional BES Interruptions.” We know only what happens in our plants, not repercussions on the grid. b. The “slow trip” entries in the “Misoperations Category” do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker – that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.
Yes
No
M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). By including different wording for a requirement in two separate documents, it creates ambiguity as to what is required by

the Reliability Standard to demonstrate compliance. These two documents should be in seamless agreement.
Yes
Group
Duke Energy
Greg Rowland
Duke Energy
No
Duke Energy does not agree with the wording in Part 3 of the definition of Misoperation. "3. Slow Trip – During Fault" identifies "Delayed Fault clearing associated with an installed high speed protection scheme" as a Misoperation, "if the high-speed performance is required to meet the performance requirements of the TPL standards". The TPL standards do not currently contain any high-speed performance requirements, and Transmission Planners must plan to meet Category C "Single Line to Ground Faults" with delayed clearing. We suggest the following alternative wording which removes the linkage to TPL standards, and puts "3. Slow Trip – During Fault" on the same footing as "1. Failure to Trip – During Fault" and "2. Failure to Trip – Other Than Fault": "3. Slow Trip – During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation as long as the overall performance of the Protection System for an Element is acceptable, and the high-speed performance is not required for coordination with other Protection Systems.)
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
O J Garcia
City of Homestead
Agree
FMPA
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the definition intent to provided a distinction between protection systems intended to isolate faulted elements and protection systems intented to operate for other system conditions. For

the latter category, we are concerned that listing the possible causes for the “other than fault” conditions may be interpreted as the only ones to watch for. Therefore we suggest that the definition should clarify that these possible conditions are not limited to those listed in the definition
No
It is unclear on what “Designate each Misoperation” in R1.2 means. If could mean identitying that it was indeed a case of protection system misoperation, or designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Yes
Yes
No
We have a difficulty determining whether or not Attachment 1 is part of the standard and therefore must be complied with. As presented, Attachment 1 is referenced under Section C 1.4, Additional Compliance Information. Section C specifies the compliance monitoring/audit evidence requirements and which are not regarded as a standard Requirement that must be complied with to achieve a reliability outcome. Further, as with the list of evidence presented in CANs and RSAWs, the information/record presented in these documents are examples of acceptable evidence. Deviations from the specified information are acceptable for so long as the information provided can demonstrate compliance with the Requirements. If the SDT holds the position that the misoperation information listed in Attachment 1 must be provided as specified, then the data requirements must be stipulated in a Requirement. Having data requirement not stipulated in a Requirement will render that data submission not mandatory.
No
We agree with the VRFs, VSLs and Time Horizons for R1, R2 and R3 but do not agree with the VRF and VSL for R4. We fully endorse the concept that a CAP needs to be implemented to ensure correct operations of the protective relay in question. However, not complying with R1 or R2 will result in not having a CAP to begin with. For this reason, we are unable to support a resulting requirement (R4) having a higher VRF than the prerequisite requirement at the front end. We therefore suggest to change the VRF for R4 to a MEDIUM. We also disagree with “The responsible entity failed to maintain records of a CAP or action plan.” in R4 to be assigned a SEVERE VSL. The main intent of R4 is to implement the CAP, whose non-compliance warrants a SEVERE VSL. However, having implemented the CAP meets the main intent of R4 and hence missing the needed documentation does not contribute to adverse reliability impact. We therefore suggest the VSL for Part 4.2 to be a LOWER, or a MEDIUM at most.
Yes
Yes
(1) There is no specific mention of UFLS and hence it is assumed that this standard applies to UFLS as well. However, there is no basis on why UFLS is included but UVLS is excluded in the Section A – 4.2 “Applicability”. There is also an apparent inconsistency between “Facilities not included” listed in section A.4.2.2 and definition related to under-voltage protection systems. The provision under 4.2 excludes the UVLS and capacitor switching from the applicability of the standard, and at the same time the definition (paragraph 2) gives as example of “other than fault”conditions the misoperation of under-voltage protection systems. (2) In the Background Section, a NOPR is mentioned but there is no specific information as to which NOPR it references. Need to add the relevant information. (3) The word “of” is missing from the bullet at the top of P.5 of the clean version.
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes

No
We agree Misoperations should be identified and their causes corrected. However, it is an administrative burden requiring entities to keep lists of ALL operations to prove compliance that EVERY operation was reviewed. It is strongly encouraged to model compliance requirements after the Internal Controls model currently be implemented in other standard projects rather than creating requirements that subject an entity to be in violation for missing documentation of a single review.
No
We urge the Drafting Team to address the time limits and report requirements utilizing the Internal Controls Process thereby eliminating the 'zero-defect' language found in the requirements. While we agree with time limits to finalize any findings we disagree with the multiple date requirements. We believe that an internal control process should be identified by the entity that eliminates the potential for administrative errors. This would allow the entity to perform necessary actions and reporting in accordance to their policy specifically on facilities determined to be critical. Where an entity has a 'no-touch' in effect of certain facilities this method would allow them to evaluate the relays off the critical period.
Yes
No
We feel the data is appropriate. However, we feel the trending data is more appropriately collected thru NERC's Section 1600 process. As no clear information is provided how the data is to be utilized we don't believe it should identified nor included as a compliance component. Further, national trending may inappropriate skew information that may be region specific diluting the results. Also, including the attachment in the standard would require a drafting team for any changes for requested data.
Yes
Yes
SMUD also encourages the development and concurrent posting of the Reliability Standard Audit Worksheet with the next standard posting.
Yes
SMUD agrees with the concepts for addressing misoperations presented in this draft PRC-004 standard. We do have concerns with the 'zero-defect' approach and urge the Standard Drafting Team to embrace the integration of Internal Controls into this reliability standard to help the entity achieve the standard's reliability objectives. This would better align the standard with ongoing activities such as the FFTR, Paragraph 81 and other tasks underway. We thank you for considering all of our comments in Questions 1 – 9 on this standard.
Group
Project 2010-05.1
Larry Raczkowski
FirstEnergy Corp
Yes
Yes
Yes
Yes
Yes

FirstEnergy (FE) agrees with the concept that this data is necessary for analysis, however, by listing the Attachment within the Compliance section would lead one to believe that Attachment 1 was part of the standard, when in actuality it is not.
Yes
No
For M4, FE would prefer to rewrite to the following: "Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that may include, but is not limited to, "
Yes
Individual
Daniela Hammons
CenterPoint Energy
No
CenterPoint Energy recommends additional clarification be included in Item 5 ‘Unnecessary Trip – During Fault’ to address interrupter device problems that result in what is commonly referred to as a “stuck breaker”. The proposed definition provides only for excluding remote tripping from a failure to trip or slow trip of a Protection System; however, interrupting device problems - other that trip coils - can also result in a failure to trip or slow trip event. Remote tripping is commonly utilized for local breaker failure schemes and for remote backup clearing for such stuck breaker events. CenterPoint Energy recommends adding wording at the end of Item 5, resulting in the following wording for ‘Unnecessary Trip - During Fault’: “A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone or from a failure to trip or slow trip of an interrupting device.”
(a) A misoperation can result in the tripping of multiple interrupting devices that can be owned by more than one entity. Also, the various components of a Protection System, such as current transformers, dc control wiring, and dc supply, can be owned by different entities. Instead of the owner of the interrupting devices that operate, CenterPoint Energy believes the owner of the protective relays should have the sole responsibility for reviewing interrupting device operations and reporting any Protection System misoperations. This would provide more consistent reporting and eliminate any duplicative responsibilities and efforts. CenterPoint Energy recommends establishing the applicability to the owner of the protective relays. (b) With the responsibility of reporting misoperations on protective relays they own, including those that are categorized as ‘Other than Fault’, the owner of the relays must review interrupting device operations whether or not they own the interrupting devices. With such a performance-based requirement, CenterPoint Energy believes it is unnecessary to establish a requirement, such as R1.1, to “Identify and review each Protection System operation”. CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: “Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified.”
No
Instead of requiring a Corrective Action Plan be developed within 60 days of identifying the root cause, as provided for in R2, CenterPoint Energy recommends the timeframe be 180 days after the date of the misoperation. Requiring a Corrective Action Plan to be developed within 60 days of identifying a root cause would create a new, additional date that must be tracked. To facilitate the ease of tracking, as well as auditing, CenterPoint Energy recommends using the following for developing a Corrective Action Plan: “For each Misoperation with an identified cause, within 180 days after the date of the misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall:”.
No
(a) CenterPoint Energy recommends deleting the second sentence in R1.1 that states: “If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation,

notify the owner of that Protection System component and provide any requested investigative information." CenterPoint Energy believes it is unnecessary to have a requirement to force entities to coordinate on misoperation analysis and corrective action, as there are existing avenues that are available, if necessary. (b) The CenterPoint Energy comments in Question 2 are related to this question. Establishing the applicability to the owner of the protective relays would establish the entity responsible for misoperations reporting. CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: "Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified."
No
(a) CenterPoint Energy is concerned that the 'Slow Trip – During Fault' misoperation example that is used in Attachment 1 may be misleading and could result in incorrect reporting; therefore, we recommend developing another example, such as, an 'Unnecessary Trip - During Fault' misoperation which is a more commonplace. Although there may not enough information included for the proposed example to know for certain, CenterPoint Energy suspects that there may have been a non-communications-based, directional time-overcurrent relay, which was part of the Protection System, which ultimately tripped the transmission line. Such a scenario may not be a reportable misoperation, as the proposed Misoperation definition for 'Slow Trip – During Fault' includes the following clarification: "Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems." In other words, the following is stated in the Guidelines and Technical Basis: "Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems." (b) The 'Equipment Voltage (kV)' field in Attachment A states: "Enter the system voltage of the BES equipment associated with the Protection System that Misoperated. For transformers, use the high side voltage." While using the high side voltage could be appropriate for generator step-up transformers, CenterPoint Energy recommends the system voltage for autotransformers be based on the low side voltage, in order to provide consistency with other NERC criteria, including Reliability Standards, such as, PRC-023 Transmission Relay Loadability.
CenterPoint Energy recommends deleting R4.2 which states the following: "Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion." With R4.1 being a performance-based requirement to "Implement the CAP or action plan", CenterPoint Energy believes it is unnecessary to establish a requirement related to documentation needs.
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Yes
BPA thanks the drafting team for their efforts as this standard has improved significantly over the previous version. While BPA believes the standard is on the right track, clarification needs to be made to a few key area's listed throughout comments below. A fair number of inadvertent operations are caused by accidental jarring of a relay panel. Since the jarring might not be due to maintenance, testing, construction, or commissioning activities, it isn't clear if it should be excluded from the definition of a misoperation by item 6. BPA suggests adding "accidental jarring" to the exclusions in item 6.
No
BPA believes requirement R1 needs to provide more clarity about which entity is required to review a protection system operation. R1 requires TO's, GO's, and DP's to review the protection system operation for an "interrupting device operation in its Facility". This is not necessarily the same thing as the owner of the interrupting device, which is who the Application Guidelines places the

responsibility on. The use of “Facility” seems inconsistent with the NERC definition of Facility: A set of electrical equipment that operates as a single BES Element. It is not clear what “in its Facility” means. The SDT appears to be using “Facility” in place of “substation”. The Rationale for R1 (blue box) mentions the owner of the interrupting device, but like R1, the rationale does not make it clear who is responsible for reviewing the protection system operation. It isn’t clear if the Rationale for R1 and the Application Guidelines are an official part of the standard, so while they might offer additional information, it is important that Requirement R1 can stand on its own and make it clear who is responsible to review the protection system operation. As presently written, BPA infers that this is not the case. Because the owner of the protective relays has the best access to the information that would be first reviewed, BPA believes that the owner of the protective relays should be required to initiate the review. From that initial review, the owner of the protective relays can then request information from other entities involved, if there are any, such as the owner of the communication system or the owner of the interrupting device. If there are different owners of the protective relays at the different terminals of an element, they should each initiate a review of their own protective relays. Requirements R2 and R3 are also unclear about who is responsible for fulfilling the requirement. Both of these specify the TO, GO, or DP as responsible for the requirement, but since there are often multiple TO’s, GO’s, or DP’s involved, which one is responsible? The Application Guideline for R2 specifies the protection system owner as being responsible. This information should be included in the Requirement itself, not just in the Application Guide. BPA believes that the owner(s) of the protection system component(s) that are identified as the cause of the misoperation in the review conducted per R1, should be responsible for R2. If there is no identified cause, the owner of the protective relay should be responsible for R3.
No
The time limits associated with R1, R2, and R3 are acceptable. Under the Compliance section, 1.4 requires a report to be submitted to the CEA within two calendar months following the end of each quarter. For an operation of an interrupting device at the end of a yearly quarter, the report will need to be submitted no more than 2 months after the operation. This will not allow the 120 days for review given by R1, nor the 60 days to develop the corrective action plan allowed by R2. BPA believes that the 2 month limit after the end of the yearly quarter to submit the report should be extended to agree with the 120 day limit of R1 and the 60 day limit of R2.
No
BPA believes the standard does not provide enough clarity for dealing with the different ownership arrangements. In addition, BPA prefers not to be required to notify other owners of misoperations in their protection systems, as each owner should be responsible for reviewing the operations on their own equipment.
No
BPA believes the data needed for metric analysis depends on what NERC hopes to learn from the data.
No
The time limits between the different VSL’s are arbitrary. For example, if an operation is analyzed within 120 days there is no violation, but if it is analyzed after more than 150 days, only 25% later, it is a severe violation. BPA believes it would be more appropriate to have only a single violation severity level of low or moderate after the 120 day deadline.
No
The language of M4 is that the evidence for R4 must include a list of five items, and the last item in the list is linked with “or”. It is not clear if the evidence must include all five items in the list, or if only one item is required. Please clarify.
Yes
Section 4.2 is titled Facilities. The NERC definition of facility is a set of electrical equipment that operates as a single BES element. The NERC definition of element is any electrical device with terminals that may be connected to other electrical devices, such as a generator, transformer, circuit breaker, bus section, or transmission line. Based on these definitions, it would seem that a protection system is not an element or a facility. BPA suggests renaming Section 4.2 to “Equipment” or “Systems”. Section 4.2.2 should be renamed from “Facilities not included” to “Protection Systems not

included" or something similar. The last paragraph of Section A.5, Background notes that PRC-004-WECC-1 overlaps with this standard and says that entities are expected to comply with the more stringent standard. Rather than leave it up to the entity to determine which of the standards is more stringent, BPA suggests simply stating which of the standards takes precedence and which can be ignored.
Individual
Bill Fowler
City of Tallahassee
No
The comment 'The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct' could be clearer. Perhaps stating 'The failure of a Protection System component is not a Misoperation as long as the Protection System operated for the fault within the zone it is designed to protect. Also, a distinction should be made whether a misoperation that only interrupts distribution and not transmission is a reportable misoperation. Example of what I am referring to is if a transformer relay trips a high side breaker but does not interrupt the BES, only distribution load.
No
1.2 requires we 'Designate each Misoperation'. I disagree with this requirement as it is inherent with the investigation that a SME will designate without it being a requirement and the need to track it.
Yes
Yes
Yes
Yes
No
I do not see any reference to Data Retention.
Yes
Group
GTC
Greg Davis
Georgia Transmission Corporation
Yes
No
Rationale for R1: State that the interrupting device owner is responsible to investigate operations initiated by a Protection System, to be consistent with the Technical Basis. For Misoperations that occur when one entity's system trips another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction.
No
GTC does not agree to the timetables and the compliance burden it places on entities: While the intent is correct, to insure that all operations are being reviewed and misoperations are found and

corrected, the quarterly reporting that we are already doing is more than sufficient. Additionally, the NERC Standards Committee approved the draft SAR for Project 2013-02 “Paragraph 81” which identifies criteria for retiring or modifying existing Reliability Standards. The proposed time limits appear to conflict with the initial criteria identified via the P81 initiative. The dated limits would likely encourage entities to shift focus on closing out documents instead of spending the appropriate time studying the operation event to determine true root cause and development of an appropriate corrective action plan. Ultimately, the introduction of time limits would have little to no impact to the protection or reliable operation of the BES, and will likely find their way to the FFT process…and thus a future candidate for elimination via P81. GTC recommends the SDT to remove these introduced limits and refine focus to results-based to achieve the desired reliability result of analyzing operations to identify misoperations and implementing corrective actions to prevent future occurrences.
No
a). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, then it should be the responsibility of the Protection System owner that caused the misoperation to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure was due to a Protection System failure by an entity that had no equipment that was interrupted or affected at the location where the Misoperation originated. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
No
1) Please change ‘Time Zone’ Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for ‘Carrier’ and one for ‘non-Carrier’ to improve the usefulness of the metrics regarding Protection System performance.
No
GTC does not agree with VSL R4 Lower VSL – Concerned statement “records were incomplete” is an opened quantifier and is not auditable, leaves to much room for interpretation for auditor. Request statement like “did not contain signed-off evidence of any revision(s) or completion of defined actionable items defined in document”.
Yes
Yes
1.)Why are UFLS schemes included in this standard but UVLS schemes are omitted? GTC recommends the addition UFLS be added to the list under Applicability section 4.2.2 (ex. 4.2.2.3). 2.)Lastly, the overall tone of the document drives entities to focusing more labor and work on the documentation of an event than completion of a correctable action. In addition, the dates for requirements and implementation seem to be defining how entities must perform work and does not give flexibility for entity to respond appropriately to problems. Possible to drive entities to provide a quick fix so they can close out documents instead of spending the appropriate time studying the event and define true root cause. Standard needs to measure performance by documenting events as misoperations with defining root cause. Should not cover expectations of an entity and drive them to a patricular performance which may drastically change their business model and performance.
Individual
Kirit Shah
Ameren
Agree

Individual
Scott Langston
City of Tallahassee
No
The comment 'The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct' could be clearer. Perhaps stating 'The failure of a Protection System component is not a Misoperation as long as the Protection System operated for the fault within the zone it is designed to protect. Also, a distinction should be made whether a misoperation that only interrupts distribution and not transmission is a reportable misoperation. Example of what I am referring to is if a transformer relay trips a high side breaker but does not interrupt the BES, only distribution load.
No
1.2 requires we 'Designate each Misoperation'. I disagree with this requirement as it is inherent with the investigation that a SME will designate without it being a requirement and the need to track it.
Yes
In lieu of R3, I agree with this.
Yes
Yes
Yes
No
I do not see any reference to Data Retention.
Yes
Individual
Scott Berry
Indiana Municipal Power Agency
No
Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).
No
This standard is for identifying and correcting Protection System misoperations. By requiring the identifying and reviewing of all interurupting device operations caused by a Protection System operation and then having the enity be found non-compliant to a requirement within this standard for not doing these actions, the SDT has made this an interrupting device operation tracking standard along with identifying and correcting misoperations. IMPA does not agree with this approach. IMPA does support the recommendation from Florida Municipal Power Agency in using the zero defect approach. In additoin, Indiana Municipal Power Agency agrees with the additional comments submitted by Florida Municipal Power Agency (FMPA)for this question.
No
Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).

In the Application Guidelines, page 18 of 22, the following statement is made: "The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records." By making this statement in the Application Guidelines, it seems to be requiring entities to have sequence of events AND Disturbance Monitoring Equipment records. IMPA believes that this is not the intent of the SDT and recommends using the words "may contain the sequence of events, relay targets,..." In addition, IMPA agrees with the comments that Florida Municipal Power Agency submitted for this question.
Group
ISO/RTO Standards Review Committee
Albert DiCaprio
PJM
Yes
No
It is unclear on what “Designate each Misoperation” means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
No
We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to provide reports within the allotted time frame. Prirorititization should be given for events that are suspected to be misoperations based on the entities’ judgment.
No
It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
No
As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES. For example, an operation of an auxililary tripping relay for tap configuration substation does not have the same BES impact as a bus differential relay scheme in a full ring configuration substation.
The SRC seeks clarification of what approvals or coordination the identitfied responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.
Individual
Ronald L Donahey
Tampa Electric Company
No
The description of “unnecessary trip”, the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not “unnecessary”) and it is intended to operate for failure or slow operation of local Protection Systems. The description for a remote back-up system operation and limimting that to only the “adjacent” zone is not appropriate. There are cases when the appropriate protection system operation may not be from the “adjacent” zone of protection. Also, the term “zone of protection” is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays

different “zones of protection”. If a zone 3 relay covers two transmission facilities, is that one and the same “zone of protection”? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc. The description of a “slow trip” as “operation slower than intended” without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
No
The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. TEC is not in favor of a zero defect approach especially when most relay operations operate correctly. TEC recommends using approaches similar to what the COM-003 and CIP v5 teams are considering. R1 does not work well with the definition of Misoperation. In other words, in order to “(d)esignate each Misoperation” as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was “slow” or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence? It would seem to TEC that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
No
TEC believes there ought to be exceptions for an “Act of Nature”, e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Applicability of 4.2.1 “Protection Systems for Facilities that are part of the BES” is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. TEC recommends using the FERC approved interpretation of PRC-004-1 Attachment 1. R3 is not needed, is administrative in nature, and provides no reliability benefit. R2 should be modified to be applicable only to misoperations where cause(s) were identified. R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted. The big change that I see for us is significantly increased documentation. Currently all of our documentation is in a database including a brief description of the corrective action plan. It seems to satisfy the new standard we would need a separate CAP document to capture all of the additional info they are asking for, we may be able to link the CAP document to our database. The standard asks for documented proof that the work associated with the CAP was actually done (data from work management system, work order etc.). Presently we just log the completion date in our database we don’t capture any proof that the work was done. Fortunately we typically only have a few misoperations per year so the volume of work will not be huge but it is just another ratcheting up of the documentation requirements. TEC doesn’t see the increased documentation requirements doing anything to increase our reliability.
Individual
Brian.J.Murphy
NextEra Energy Inc.
Yes
Yes
No

NextEra Energy Inc. (NextEra) disagrees that 120 days provides sufficient time to investigate all types of misoperations. For example, NextEra does not agree with the rationale that 120 days is sufficient time to account for outage constraints. This timeframe is particularly troubling in the context of nuclear power plants that generally do not schedule a switchyard outage unless it is consistent with its refueling outage – which can be as long as 18 months apart. Thus, NextEra recommends that R1.3 be revised as follows to provide a clearer process and more flexibility: 1.3 Investigate each potential Misoperation and document the findings. The cause of a Misoperation may be initially listed as “Unknown/unexplainable” and the Analysis and Corrective Action Status listed as “Analysis – In Progress”. The entity should continue their normal process of investigation and after a cause is determined resubmit the Misoperation to update the information.
Yes
Yes
NextEra has no issue with the information requested or the format, but requests that NERC and the regions all use the same form for the collection of misoperation data.
No
NextEra disagrees with the approach taken in the VSLs that provides a range of days to determine the severity of the violation. The importance of investing and implementing a correct action plan for a misoperation varies on the type of misoperation and the need or not to implement a corrective action to address reliability. NextEra favors all aspects of the Reliability Standards moving to a risk, results based approach, including VSLs. Thus, the VSLs should be re-drafted to measure whether an entity has timely implemented a corrective action plan for misoperations that pose a risk to reliability, with consideration of the level of the risk and other factors such as complexity of the issue, costs and outages, etc.
No
NextEra disagrees with the data retention periods, given that it is also submitting quarterly reports. Specifically, from a monitoring and compliance perspective, there should be no need to maintain all data in between audits if the entity is also submitting quarterly reports. Instead, the entity should only be required to maintain one years worth of data. Since, at any time, a regional entity can via a spot check or a compliance audit review data to access compliance, it seems redundant and onerous to require that the entity stockpile three to six years of data related to misoperatrions depending on their audit cycle. Moreover, such a data retention requirement seems to be inconsistent with NERC’s movement to a risk and results based approach rather than a review of past evidence and a check list approach to compliance. Accordingly, NextEra requests that the data retention be reduced to only one year.
Yes
NextEra encourages the Standards Drafting Team to improve the wording used in R2. At this time, the wording appears to apply to all situations without qualification and does not consider several situations that may relevant. To clarify the language, NextEra recommends the following changes to R2. “R2. Within 60 calendar days of identifying the cause(s) of each Misoperation pursuant to R1.3, the Transmission Owner, Generator Owner, or Distribution Provider shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Draft a Corrective Action Plan (CAP) for the identified Protection System component(s), including, if applicable, the following: (i) an evaluation of the CAP’s applicability to the entity’s other Protection Systems, and (ii) an explanation of why corrective actions are either: (i) beyond the entity’s control; (ii) cost prohibitive/significantly impacted by cost considerations; (iii) not to be implemented for over 5 years or (iv) would reduce BES reliability.” Similar to the re-write of R2, NextEra does not see the need for a “declaration” in R3. Thus, NextEra recommends that the second bullet in R3 be redrafted to read: “o An explanation of why no further actions will be taken.” NextEra opposes the use of “detailed” in R4.2 as unnecessary, subjective and onerous. PRC-004-3 should not be written so that an entity can be found in violation because of subjective judgments on what is or what is not detailed. Further, NextEra finds that the clarity of R4.2 may be improved. Thus, NextEra recommends that R4.2 be redrafted as follows: “4.2 Maintain implementation records for each CAP and action plan, including the dates of any revision(s) and completion.” Lastly, for clarity, NextEra also believes there should be linkage between R2 and R4 on the issue of applicability to other Protection Systems at other locations, and, thus, suggests the

following changes to R4.1. “4.1 Implement the CAP or action plan, including, as applicable, the entity’s Protection Systems at other locations that were identified in R2.”
Group
MEAG Power, Steve Jackson, Steve Grego, Danny Dees
Scott Miller
MEAG Power
Agree
OPPD
Individual
David Jendras
Ameren Services
No
(1) We suggest, In #3 Slow Trip, to replace “or by coordination requirements with other Protection Systems” with “or to meet the coordination requirements with other Protection Systems in accordance with applicable PRC standards.” For example, entities regularly install one pilot relaying system on a line for other reasons, such as end use power quality. The failure of such a pilot relaying system to trip high speed should not be classified as a Misoperation. (2) We suggest to insert “the operation” to clarify #6 yielding “Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the operation is unrelated to on-site maintenance, testing, construction or commissioning activities.”
Yes
(1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain “…such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.” A narrow interpretation of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. (2) Clarify that the rationale is consistent with the Technical Basis page 17, by clearly stating that “the interrupting device owner is responsible to investigate operations initiated by a Protection System.” (3) We suggest to augment the Rationale by adding at the end, “…and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information.” A fair number of Misoperations trip another entity’s interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner’s responsibility to report the Misoperation. We believe that under the present PRC-004-2a, there is confusion on this distinction. (4) We suugest to change R1 1.2 to “Designate each operation as correct or a Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps.” IEEE 1366 (GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES) defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.
No
(1) We suggest that “cause(s)” be changed to “cause” in R2 to avoid time limit confusion, and be consistent with the use of “cause” throughout the rest of this standard. (2) Although wording is clear that R2 be completed within 60 days of identifying the cause, some entities may incur violations by glibly adding the 120 days in R1 to the 60 days in R2. We suggest pointing out that the entity will have to intentionally record and track when they’ve identified the cause, and providing an example in the Application Guidelines for R2 on page 18 will provide better clarity. For example, if the entity identifies the cause on 3/31 for a 3/1 Misoperation, they must develop and document R2 CAP by 5/30 (not 8/29). (3) We agree with the SERC PCS that introducing time limits is unwarranted and burdensome. Regional Entities now get quarterly Misoperation and CAP status reports and have sufficient information to monitor progress. At most, a one year time limit for CAP completion or explanation of CAP duration could be used. A small number of CAPs will extend beyond one year due

to their scope or outage restrictions. SERC has used a two year limit then requiring a formal explanation, and very, very few have reached this time limit.
Yes
Yes, as long as the R1 rationale is augmented to clarify reporting responsibility as we recommend in items 2 and 3 of question 2 above.
No
We suggest to (1) change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. (2) split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. (3) split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. (4) eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. (5) Align Attachment 1 with the present reporting template to ease burden on entities. We also believe that (a) Declarations should be included in the Attachment 1 reporting template and (b) The reporting template should be contrived so that it automatically documents and thus provides much of the evidence required by the standard.
No
(1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. We suggest that the SDT make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. (2) R2 VRF measures duration from 'completion of the investigation or receiving notification' but R2 itself measures from 'identifying the cause(s) of each Misoperation'. We suggest t that the SDT change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.
Yes
We suggest that the SDT clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the last audit.
Yes
(1) Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as Update Submittal Type once it becomes effective? (2) Six months after approval may be too short a time to modify processes and software to efficiently meet the PRC-004-3 requirements and supporting evidence.
(1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP "includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period. (2) We suggest that the SDT reword C.1.4 from "Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA..." to "For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA..." This clarifies who is responsible for submitting when multiple entities are involved. (3) Attachment 1 "Action Plan/Declaration Development Date" example data should be "N/A". (4) Application Guidelines – Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, is sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, we suggest that the SDT also state: (a) the total number of non-weather related causes; b) the total number of causes; (c) its rank when BES outages related to weather are included; d) the top three non-weather related causes; (e) its rank in terms of BES unavailability; and f) the % of unavailability

caused by Failed Protection System Equipment. (5) M4 on page 8: We suggest t that the SDT replace 'must include' with 'may include' because some items do not apply to every CAP or action plan. Clearly the entity must document the implementation of each CAP and action plan, beyond that the range of documentation will vary depending on the situation. (6) Ameren agrees with and supports the comments of the SERC Protection & Control Subcommittee. (7) We suggest that the SDT augment the Application Guidelines Requirement 2 examples on page 17 to include "an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." (8) We suggest that the SDT modify the Application Guidelines Requirement 1 wording on top of page 18 to make it clear that the suggested information should only be included as appropriate. The cause of some Misoperations is quite obvious and does not need copious tests, DFR records, and the like. For example, carrier switch may've been in the wrong position. (9) Editorial comments: a) p4 Applicability box – replace 'RMS' with 'RAS'; b) p5 Background 3rd line – Misoperation should be singular.
Group
Southern Company
Antonio Grayson
Operations Compliance
No
• Instead of clarification and specification, the objective of the change to the definition should be simplification. A simpler definition could be: Failure of a Protection System to operate as intended, evidenced by it not operating when it should have, operating when it should not have, or operating slower than it was intended to operate. • If the definition remains in the present form, we would suggest slight changes to language on #1 and #2: (The failure of……..of the Protection System for the element it is designed to protect is correct.) • Suggest slight changes to language on #3: (Delayed Fault clearing ……..high-speed performance has been identified as required……) • Please clarify why # 3 and # 4 are not a subset of # 1.If not, it should be made clear in the verbiage.
No
• The question is missing a key component: Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, designate each Misoperation, and investigate each misoperation and document the findings… The first two items are reasonable; however, the 120 days to 'and investigate each misoperation and document the findings…' can be problematic and creates a documentation requirement for something that is still under investigation. See Comment below about timeframes. • The requirement says entities will "review each Protection System operation that operates the entity's interrupting device…". In R1, the requirement to "designate" is not defined. Is this a classification of each operation as a correct operation or a misoperation (as indicated by the VSL)? Or is this an annotation of each operation per Attachment 1? Or is this a declaration of which type of misoperation this is? Or other? Would a spreadsheet with each operation listed with an indication of correct or incorrect with a date noted be sufficient; or is other docuemtnation required? • What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "…such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. • In addition, under R1.1, the second requirement associated with notification of another entity should be stated as a separate subrequirement.
No
• We do not agree with the introduction of the noted timeframes. There is no indication that the extremely large percentage of entities have not been doing due diligence in analyzing operations, identifying misopertions, and taking appropriate actions to prevent reoccurrence all of which are inherent to the existing Standard. If the only reason to place these time limits is to have a basis for compliance (i.e. you can't require someone to do something unless you tell him how long he has, because he can always say 'I was going to do it tomorrow); then, the time limits should be removed. We offer two potential suggestions for improvement: o R1 should not be changed from the previous posting. The requirement should be that the entity has a procedure and process. Compliance can be

gauged based on an entities compliance culture, oversight and review of processes and procedures. The SDT should utilize the approached introduced in their recently posted- COM-3. or o It is suggested that all Protection System operations for a given quarter are reviewed, analyzed, classified before the reporting due date to the RE (at the end of two calendar months following the quarter) – this will cover all of the deadlines found in requirements R1, R2, and R3. Also, we believe that any required CAP should be developed and documented by this same date. Placing the 120 day and 60 day time frames for each Prot Sys operation unnecessarily complicates the evaluation, resolution, tracking, and documentation of each misoperation. For a large entity with many operations per quarter, the multiple time frames for R1, R2, and R3 are unecessarily overbearing. • Requirement R3 should be combined with Requirement R2. A CAP developed and documented as described in R2 can address resolving identified causes of misoperations as well as addressing additional investigative plans for determining a cause. Misoperations with no identified cause can be handled as described in the draft standard.
No
• It is noted in the Rational box for R1 that the owner of the component that cause the misop will create the CAP, etc. As such it is not clear who will report the Misoperation. i.e. If Owner A has a breaker open for a fault outside the zone due to a carrier that failed to send a block signal. Is an entities only responsibility to communicate to the other owner that his equipment didn’t operate correctly? If so how do they know he ever reported it and/or did anything to correct the problem. It seems that the misoperation should be reported by the entities whose interrupting device opened in error. • Please clarify the statement in the Rational Box for R1: “The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request.
No
• This list is not inclusive of the present RAPA form. The SDT should insure that the RAPA form is modified to only include the data specified in the Standard. • The TADS information should be removed since there are plans to start reporting # of operations thereby allowing appropriate metric analysis • However, we have a number of recommendations intended to improve the structure and clarity of the standard and Attachment 1: a) The requirement for reporting should be in the Requirements and Measures section as a requirement rather than in the Compliance section C1.4. Attachment 1 needs to be part of the standard since it is referenced in the standard. b) The Registered Entity ID # is not needed as the data submission occurs via web based portals and the RE knows who is submitting the data based on the log in credentials of the submitter. This information is superfluous. c) The "Event Analysis Completion Date" and "Corrective Action Plan/Declaration Development Date" fields are not required if the combined R1 & R2 suggestion is implemented along with the deadline for these requirements being the report date to the RE. d) There are too many classification choices in the "Resolution Status" field. One of three choices should be adequate to tell the RE what stage of evaluation/resolution is active: 1) Analysis – In Progress, which means [Still Under Investigation]; 2) Analysis – Completed – Corrective Action Plan Pending; 3) Corrective Action – Completed, which means [Investigation Complete, Corrective Action Complete] e) Both the "Target Resolution Completion Date" and the "Actual Resolution Completion Date" fields are not needed. We suggest using only the "Target" date field and have the RE look at the Resolution Status field to determine if the Action Plan is Completed. We believe that all of these reporting dates are not necessary. f) The "Date Reported" field is not needed - the submission due dates are fixed by the RE (and have been repeated on page 21 of the Clean draft standard dated 6 Jul 2012. g) We believe that a linkage to GADS reporting is not necessary. In the many years we have been processing relay operations, we have had no reason to review any GADS information. The mis-opeation reporting and resolutino can be processed without the addition of non-useful information.
No
a)VSLsfor the draft R1 and R2 should change based on the new time frame suggested in our response to Q2 and Q3. For the CAP development and documentation, keep only the "failed to develop..." as a VSL. b) The VSL shown for R3 reveals that R3 is not needed - the development and documentation of the CAP is the subject of the drafted R2, and the implementation of a CAP is the subject of the drafted R4. c) The severe VSL for R3 incorrectly lists implementation of the CAP as a measure - implementation of the CAP is the subject of the draft Requirement 4. d) We suggest that the Severe VSL for R4 be the only VSL for that requirement. e) The VRF for R4 is too high. It should match the other requirements - if the CAP is not implemented, there is no additional risk than if a

Protection System operation is not reviewed. A new requirement for reporting to the RE should carry a low VRF.
No
• The first paragraph of compliance Section 1.2 Evidence Retention is not needed and should be removed. (It is redundant to the second paragraph.) • M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Yes
• There needs to be some consistency between the proposed PRC-004, and PRC-005. How can one say a given Protection System needs to be maintained for the BES Reliability, but not necessarily operations analyzed. o The Applicability of PRC-004: Protection Systems for Facilities that are part of the BES. o The Applicability of PRC-005-2: 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) • Please clarify the PRC-004 Applicability related to generators. It would indicate that all protection systems at a generating plant that is part of the BES would be included. Is that the intent or is it only the Protection Systems associated with the protection of the Generator and/or step-up bank? • We suggest separating the Guideline and Technical Basis document from the remainder of the standard so that the document is less overbearing. • As stated in the responses to several earlier questions, we recommend combining R2 with R1 and making the deadline for each the date of reporting to the RE, eliminating R3, renumbering R4 to R2, adding the reviesd version of Attachment 1 to the standard, and adding a new requirement which specifies the reporting responsibilities that are contained in the Compliance section C1.4. Based on our experience as a large utility in investigating, tracking, and reporting relay operations and misoperations, we believe these changes will be simpler, more efficient, more cost effective to implement while still achieving the desired goals.
Group
JEA
Tom McElhinney
JEA
No
JEA suggests a shorter definition such as: either the operation of a protection system when it should not or the failure to operate when it should.
No
It does not appear to be cost effective to identify and review each PS operation. Also, as time goes on and issues are found and resolved this standard becomes even less beneficial because of the ever decreasing percentage of misoperations that should result from the standard.
No
If outages are necessary to properly examine and test protection system components 120 days may be too short especially during storm season. We recommend this be increased to 180 days. R1 also needs exceptions for major system events and natural disasters. The R2 time frame of 60 days to develop a corrective Action Plan for the components of Protection misoperations is insufficient to consider applicability to other protection systems, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. Since the clock starts ticking as soon as the cause is identified, this should be extended to 180 days. Again it seems prudent to have an exception for major system events and natural disasters. If R1 & R2 timeframes were increased as suggested above this should result in an increase in this area also since the 180 day time frame was arrived at by adding the two preceding time frames. The new resulting time frame should be 360 days.
No
R1.1 requires that if an entity suspects a Protection System component(s) owned by another entity

contributed to a Misoperation then we are to notify the owner of that Protection System component and provide any requested investigative information. We recommend to add language such as the notified entity must provide any requested information.
No
Attachment 1 Field Name: Misoperational General Cause Field Value: Incorrect settings/Logical Design Errors are not a misoperation since the protection system operated exactly as it was programmed. Improper setting should be handled in PRC-005 (maintenance and testing). If we are going to include things that cause a protection system to not protect then there is little justification for not considering other equally as destructive problems such as the breaker opening slowly. It is inconsistent to send the message that human error is a problem but mechanical error is not. Also by excluding human error they could better correlate with TADS, since TADS excludes human error for relay settings. Section 1.4 clearly shows this is a requirement and so if it is required then make it a requirement and if it is not required then delete it.
No
This increases from low to severe by 10 day increments so if it takes you 5 months instead of 4 you are at a severe VSL. Also missing just one review results in a severe level. Also not notifying an adjacent entity that you think they may have contributed to the problem is a severe violation – the severity should be based on the number of occurances. We think that 30 day increments are appropriate and severity levels should also be based on the percentage of missed reviews such as 1%, 2%, 5%.
We believe this would be a good candidate for the new cost benefit approach. Also we believe that this is the wrong approach. NERC should focus on fixing the problem (PRC003 not being approved) by working on PRC003 instead of changing PRC004 to address deficiencies caused by lack of an approved PRC003 standard.
Individual
Patrick Brown
Essential Power, LLC
No
The proposed definitions are unnecessarily complicated. Also, the "catch all" category "Unnecessary Trip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out. We would also like to see language that addresses an “Unnecessary Trip-During Fault – A Protection System operation for a Fault for which the Protection System is intended to operate, but operates prior to the required element setting.”
No
In R1, the requirement to “designate” is not defined. The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor. This form of protection is more "visible" during a normal stop event, but a reverse power relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitly stated that reverse power trips during a normal stop event be not considered as Misoperations. It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop

(ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section). The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO's standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to function.
Yes
Yes
No
There are too many classification choices in the "Resolution Status" field of the report form. An equally effective status report can be delivered using three choices: 1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed – Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] The form for GOs should differ from that for TOs, for the following reasons: a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid. b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker – that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). Additionally, there is no reference to reporting in a manner outlined by the CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
No
Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
No
M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Yes
Compliance section C1.4 contains a requirement to report to the RE – this needs to be in the requirement section of the standard.
Individual

Darryl Curtis
Oncor Electric Delivery
Yes
No
The proposed R1 obligates the Transmission Owner or Generation Owner to now provide notification, coordinate communication and maintain documentation follow up with neighboring entities. It appears to misalign with the NERC Event Analysis program. In addition, the Regional Entities have been tasked with designing a misoperations procedure for all Registered Entities in their respective area which appears to overlap this Requirement. Oncor recommends the appropriate NERC/Regional Entity subgroups revaluate to align NERC misoperations reporting which will ensure streamlined processes for Registered Entities.
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
Yes
No
R1 requires detailed investigation of every protection system operation. If operational data indicates that only the intended breakers operated for a fault on a specific protected line and a fault record from any monitoring device in the area indicates the fault was cleared in the intended time then no detailed review of the protection system operation is required.
No
R2 requires development of a CAP and evaluation of CAP applicability to other locations. I recommend development of a CAP in 60 days for the specific location where the misoperation occurred. CAP applicability to other locations may require more time depending on what the CAP involves. CAP applicability to other locations should be allowed a longer time frame such as 12 months. R3 requires development of an action plan for misoperations with an unknown cause. Depending on the type of protection equipment in place it may not be possible to always determine the cause of every misoperation. For example electromechanical relays only provide targets and event reports may not be available. R3 seems to require that EM relays be changed out to digital relays in order to monitor for the next misoperation. The standard should not require this and R3 should be deleted.
Yes
Yes

Yes
Yes
Individual
Alice Ireland
Xcel Energy
1) Regarding R1.1, it is not clear which entity would report the Misoperation, or be responsible for the remaining requirements. Would it be a joint responsibility? Please consider revising the requirement to indicate that the entities must agree on which one would handle the misoperation process, while the other would support as needed. 2) Consider including RAS/SPS, UVLS, UFLS under the applicability and eliminating the standards associated with misoperations on those specific types of protection systems.

Consideration of Comments

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

The Protection Systems: Phase 1 (Misoperations) Drafting Team thanks all commenters who submitted comments on the second draft of the PRC-004-3 standard for Protection System Misoperations. These standards were posted for a 45-day public comment period from July 25, 2012 through September 7, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 95 sets of comments, including comments from approximately 230 different people from approximately 145 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received

Definition

The drafting team made several changes to the definition. The term 'composite Protection System' was incorporated into the introductory sentence of the definition to indicate that a Misoperation pertains to the 'composite Protection System' and clarify that only the overall performance of the Protection System is considered when determining a Misoperation. The definition categories were edited and revised to provide more specificity and clarity.

Applicability

The drafting team revised the Facilities portion of the Applicability section to provide more specificity. Facilities 'included' are stated in 4.2.1 and 4.2.2, and facilities excluded are stated in 4.2.3 and 4.2.4. The Applicability text box provides explanation for the exclusion of the facilities listed in 4.2.3 and 4.2.4.

Requirements

The drafting team revised Requirement R1 to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs.

The drafting team revised Requirement R4, removing the parts to eliminate the administrative aspects.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Measures

The drafting team modified the measures to complement the revised requirements.

Compliance

C 1.2 Evidence Retention – The following sentence was added for clarity: "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period."

The boiler plate language was modified for clarity.

C 1.4 Additional Compliance Information – The language was removed. All reporting obligations have been removed from the standard.

VLSs

Complementary changes were made to the VSLs in conjunction with the revised requirements.

Guidelines and Technical Basis

Complementary changes were made to the Guidelines and Technical Basis corresponding to all changes to the standard. More supporting discussions, explanations, and examples for all aspects of the standard were provided.

Implementation Plan

The Effective Date was revised from six months to twelve months following applicable regulatory approvals. Other complementary changes were made to the Implementation Plan.

Unresolved Minority Views

- A few commenters expressed concern about the 120 day timeframe to review Protection System operations. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations as well as outage constraints for investigative purposes. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

- A few commenters felt having formal notification to another entity of an operation was unnecessary. The drafting team disagreed and clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. If the investigation doesn't reveal a cause within this timeframe, the notified entity has the remainder of the 120-day period, and if needed can establish an action plan (per Requirement R3) with its own time table for further investigation to determine whether their component operated correctly.

- Several commenters asked the drafting team to combine all or parts of Requirements R1, R2 and R3 into one requirement with one timeframe. The drafting team believes an overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.

- A large percentage of the entities that commented stated that the 10-day intervals between severity levels for Requirements R1, R2, or R3 were too short. The drafting team used the NERC guideline: "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended." However, based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Ben Wu	Orange and Rockland Utilities	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
19.	Brian Robinson	Utility Services	NPCC	8
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2

2.	Group	Steve Alexanderson	Western Small Entity Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dale Dunkel	Okanagan PUD	WECC	1
2.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
3.	Steven J. Grega	Public Utility District #1 of Lewis County	WECC	5
4.	Steven Powell	Trans Bay Cable	WECC	1
5.	Eric Scott	City of Palo Alto	WECC	3
6.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3
7.	Ronald Sporseen	Central Electric Cooperative	WECC	3
8.	Ronald Sporseen	Consumers Power	WECC	1, 3
9.	Ronald Sporseen	Clearwater Power Company	WECC	3
10.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3
11.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3
12.	Ronald Sporseen	Northern Lights	WECC	3
13.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3
14.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3
15.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3
16.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3
17.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	1, 3

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

18.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3
19.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	4
20.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8
21.	Ronald Sporseen	Power Resources Cooperative	WECC	3, 5
22.	Ronald Sporseen	Lane Electric Cooperative	WECC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Brad Haralson	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jonathan Hayes	Souhwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	John Allen	City Utilities of Springfield	SPP	1, 4
4.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
5.	Tim Bobb	Westar Energy	SPP	1, 3, 5, 6
6.	John Boshears	City Utilities of Springfield	SPP	1, 4
7.	Anthony Cassmeyer	Western Farmers	SPP	1, 3, 5
8.	Gary Condict	Sunflower Electric Power Corporation	SPP	1
9.	Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
10.	Shawn Jacobs	Oklahoma Gas and Electric	SPP	1, 3, 5

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

11. Stephen McGie	City of Coffeyville	SPP	NA
12. Ron McIvor	Omaha Public Power District	MRO	1, 3, 5
13. Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
14. Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
15. Terri Pyle	Oklahoma Gas and Electric	SPP	1, 3, 5
16. Sandra Sanscrainte	ITC holdings	SPP	NA
17. Katie Shea	Westar Energy	SPP	1, 3, 5, 6
18. Jamie Strickland	Oklahoma Gas and Electric	SPP	1, 3, 5
19. Steven Stout	ITC holdings	SPP	NA
20. John Zipp	ITC holdings	SPP	NA
21. Brandon Desbrough	ITC holdings	SPP	NA
22. Doug Jackson	Grand River Dam Authority	SPP	1, 3, 5
23. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
24. Ashley Stringer	OMPA	SPP	4

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Kent Kujala	Detroit Edison			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Steven	Kerkmaz	RFC	3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Chang Choi	Tacoma Power	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Travis Metcalfe	Tacoma Public Utilities	WECC	3
2. Keith Morisette	Tacoma Public Utilities	WECC	4
3. Chris Mattson	City of Tacoma	WECC	5
4. Michael Hill	Tacoma Public Utilities	WECC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Rhonda Bryant	El Paso Electric	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dennis Malone	El Paso Electric	WECC	1
2. Tracy Van Slyke	El Paso Electric	WECC	3
3. David Hawkins	El Paso Electric	WECC	5
4. Tony Soto	El Paso Electric	WECC	6

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Glenn Stephens	Santee Cooper	SERC	1
2.	Kevin Bevins	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	5
5.	S. T. Abrams	Santee Cooper	SERC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tom Owens	ELECTRIC TRANSMISSION RELIABILITY	SERC	1, 3
2.	Rick Purdy	ELECTRIC TRANSMISSION RELIABILITY	SERC	1, 3
3.	Larry Whanger	F&H System	SERC	5
4.	Chip Humphrey	F&H Merchant	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Joe Spencer	SERC Protection and Control Subcommittee (PCS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	George Pitts (Co-chair)	TVA	SERC	
2.	Stony Martin	Santee Cooper	SERC	
3.	Russ Evans	SCE&G	SERC	
4.	Paul Nauert (Co-chair)	Ameren	SERC	
5.	John Miller	GTC	SERC	
6.	Bridget Coffman	Santee Cooper	SERC	
7.	Jerry Blackley	Duke Energy	SERC	
8.	Rick Purdy	Dominion	SERC	
9.	Steve Edwards	Dominion	SERC	
10.	Joel Masters	SCE&G	SERC	
11.	David Fountain	Duke Energy	SERC	
12.	Phil Winston	Southern Co.	SERC	
13.	David Greene	SERC	SERC	

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

14.	Joe Spencer	SERC	SERC

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
3.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Morland	Colorado Springs Utilities	WECC	1
2.	Charles Morgan	Colorado Springs Utilities	WECC	3
3.	Clint Jolly	Colorado Springs Utilities	WECC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16. Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates			X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
2.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
3.			WECC	5
4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6

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

6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Larry Raczkowski	Project 2010-05.1	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FE	RFC	1
2.	Steve Kern	FE	RFC	3
3.	Doug Hohlbaugh	FE	RFC	4
4.	Ken Dresner	FE	RFC	5
5.	Kevin Querry	FE	RFC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean	Bender	WECC	1
2.	Dan	Goodrich	WECC	1
3.	Fran	Halpin	WECC	5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Group	Greg Davis	GTC	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Luke	GTC	SERC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Ben Li	IESO	NPCC	2
3.	Ali Miremadi	CAISO	WECC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
4. Stephanie Monzon	PJM	RFC 2										
5. Steve Myers	ERCOT	ERCOT 2										
6. Bill Phillips	MISO	RFC 2										
7. Charles Yeung	SPP	SPP 2										
22. Group	Scott Miller	MEAG Power	X		X		X					
Steve Jackson Steve Grego Danny Dees												
23. Group	Tom McElhinney	JEA	X		X		X					
Additional Member	Additional Organization	Region / Segment Selection										
1. Ted Hobson		FRCC 1										
2. Garry Baker		FRCC 3										
3. John Babik		FRCC 5										
24. Group	Emily Pennel	Southwest Power Pool Regional Entity										X
No additional members listed.												
25. Individual	Heidt Melson	SPCWG		X								X
26. Individual	Ed Croft	Operational Compliance	X		X		X					
27. Individual	Sara McCoy	Electric Reliablity Compliance	X		X		X	X				
28. Individual	H. Pat Caldwell	TVA Transmission Operations and Maintenance	X									
29. Individual	Cole Brodine	Nebraska Public Power District	X		X		X					
30. Individual	Ryan Millard	PacifiCorp	X		X		X	X				
31. Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
32. Individual	Antonio Grayson	Southern Company	X		X		X	X				
33. Individual	Dale Dunckel	Okanogan PUD	X									
34. Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
35. Individual	Michael Jones	National Grid	X		X							
36. Individual	Michael Moltane	ITC	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Terri Pyle	Oklahoma Gas & Electric	X		X		X					
38.	Individual	Paul Haase	seattle city light	X		X	X	X					
39.	Individual	Louis C. Guidry	Cleco Corporation	X		X		X	X				
40.	Individual	NICOLE BUCKMAN	ATLANTIC CITY ELECTRIC COMPANY			X							
41.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
44.	Individual	Bill Middaugh	Tri-State G&T	X									
45.	Individual	John Canavan	NorthWestern Energy	X									
46.	Individual	Jack Stamper	Clark Public Utilities	X									
47.	Individual	Thad Ness	American Electric Power	X		X		X	X				
48.	Individual	Anthony Jablonski	ReliabilityFirst										X
49.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
50.	Individual	Robert Dintelman	Utility System Efficiencies, Inc.										
51.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X					
52.	Individual	Timothy Brown	Idaho Power Co.	X		X							
53.	Individual	Angela Gaines (for Kellie Cloud)	Portland General Electric Company	X		X		X	X				
54.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
55.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
56.	Individual	Saul Rojas	New York Power Authority	X		X		X	X				
57.	Individual	Mark F. Draper	Exelon Corp.	X		X		X	X				
58.	Individual	Mark R. Jones	Potomac Electric Power Company			X							
59.	Individual	Mike Weir	Dairyland Power Cooperative	X		X		X					
60.	Individual	Marie Knox	MISO		X								
61.	Individual	David Burke	Orange and Rockland Utilities	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
62.	Individual	Melissa Kurtz	US Army Corps of Engineers	X				X					
63.	Individual	Thomas Foreman	Lower Colorado River Authority					X					
64.	Individual	Jim Cyrulewski	JDRJC Associates								X		
65.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X							
66.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
67.	Individual	Don Jones	Texas Reliability Entity										X
68.	Individual	d mason	HHWP					X					
69.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
70.	Individual	Ed O'Brien	Modesto Irrigation District			X	X		X				
71.	Individual	Martin Bauer	US Bureau of Reclamation					X					
72.	Individual	Christina Koncz	PSEG	X		X		X	X				
73.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
74.	Individual	Andrew Z.Pusztai	American Transmission Company	X									
75.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
76.	Individual	Clay Young	South Carolina Electric and Gas	X		X		X	X				
77.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
78.	Individual	J. S. Stonecipher, PE	City of Jacksonville Beach, FL dba/ Beaches Energy Services	X								X	
79.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
80.	Individual	Mike Hirst	Cogentrix Energy, LLC					X					
81.	Individual	O J Garcia	City of Homestead			X							
82.	Individual	Michael Falvo	Independent Electricity System Operator		X								
83.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
84.	Individual	Daniela Hammons	CenterPoint Energy	X									
85.	Individual	Bill Fowler	City of Tallahassee			X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
86.	Individual	Kirit Shah	Ameren	X		X		X	X				
87.	Individual	Scott Langston	City of Tallahassee	X									
88.	Individual	Scott Berry	Indiana Municipal Power Agency	X		X	X	X	X				
89.	Individual	Ronald L Donahey	Tampa Electric Company										
90.	Individual	Brian.J.Murphy	NextEra Energy Inc.	X		X		X	X				
91.	Individual	David Jendras	Ameren Services	X		X		X	X				
92.	Individual	Patrick Brown	Essential Power, LLC					X					
93.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
94.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
95.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Yes or No	Entity Name
MEAG Power, Steve Jackson, Steve Grego, Danny Dees	Agree	OPPD
SPCWG	Agree	
Electric Reliablity Compliance	Agree	Lower Colorado River Authority (LCRA)
Hydro-Quebec TransEnergie	Agree	NPCC
Oklahoma Gas & Electric	Agree	Southwest Power Pool
ATLANTIC CITY ELECTRIC COMPANY	Agree	PEPCO HOLDINGS INC AND AFFILIATES
Delmarva Power & Light Company	Agree	Pepco Holdings Inc. and Affiliates
Lincoln Electric System	Agree	Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Potomac Electric Power Company	Agree	Pepco Holdings Inc. and Affiliates
US Army Corps of Engineers	Agree	MRO NSRF
Lower Colorado River Authority	Agree	Lower Colorado River Authority Segment 1
JDRJC Associates	Agree	Midwest ISO

Organization	Yes or No	Entity Name
HHWP	Agree	NAGFI wanted to provide additional comment related to the implementation plan and was unable to undue the "Agree" radio button We believe that the six-month implementation timeline is insufficient for many small entities to revise existing misoperations identification and analysis procedures and provide appropriate training to relevant staff. We also would like to see all implementation plans include training key Standard requirements or changes, and CEA expectations for basic compliance.
Response: Thank you for your comment. This requires discussion and coordination with the responses to question 8.		
American Transmission Company	Agree	ATC endorses and agrees with comments submitted by the MRO NSRF.
South Carolina Electric and Gas	Agree	SERC PCS
City of Homestead	Agree	FMPA
Ameren	Agree	

1. **The definition of "Misoperation" has been revised from the initial posting. Do you agree with the revised definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

Several commenters asked the drafting team to define and use the term 'composite Protection System' in the standard. To address these comments, the drafting team clarified the Misoperation definition by modifying the introductory sentence of the definition to indicate that a Misoperation pertains to the 'composite Protection System'. The Guidelines and Technical Basis section of the draft standard was also updated to explain that the 'composite Protection System' for an Element is its total complement of protection.

Several commenters suggested that the parenthetical phrases were subordinate in the categories listed in the Misoperation definition. The drafting team responded by removing the parentheses around the exclusionary phrases.

Several commenters questioned the range of activities included in the reference to "on-site" activities as used in the definition. In regards to part 6 of the definition (Unnecessary Trip - Other Than Fault), the drafting team explained that "on-site" refers to on-going activities at BES Facilities. However, it was made clear that once the activities have been completed and the equipment released from service, the exclusion regarding "on-site" activities no longer applies regardless of the presence of personnel at the location. "Inspection" was added to the list of "on-site" activities that could initiate an operation but should exclude it from being considered a Misoperation.

Some commenters questioned category 5 of the definition (Unnecessary Trip - During Fault). These commenters asked for clarity on the exclusionary phrase and suggested that the word "adjacent" be removed or replaced. The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.

One commenter asked for the exclusionary phrase in category 3 of the definition (Slow Trip - During Fault) to be expressed in a way that was more consistent with the rest of the definition. The drafting team revised category 3 to be similar to the first two parts of the definition.

A few commenters questioned whether Underfrequency Load Shedding (UFLS) was covered by the standard. The drafting team clarified the issue by modifying the 'included' Facilities portion of the Applicability section to specifically include Underfrequency Load Shedding (UFLS) that trips a BES Element.

Several commenters asked for clarification regarding the phrase "slower than intended" in categories 3 and 4 of the definition. The drafting team explained that the phrase means that the Protection System operated slower than the objective of the owner(s).

Several commenters questioned the reference to the TPL standards in the definition. The drafting team explained that the reference (made in category 3 of the definition) to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent

dynamic instability. The performance requirements in the TPL standards indicate stability, thermal and voltage limits and loss of Demand impacts for contingencies and are found in Table 1 of those standards.

Some commenters expressed concerns regarding the extent of non-Fault conditions. The drafting team advised that the examples used in categories 2 and 4 of the definition were not meant to be an all-inclusive list.

Several commenters preferred a shorter, simpler definition. The drafting team declined to make the suggested changes because a brief definition could be open to varying interpretations due to lack of detail.

Several commenters asked to exclude weather events and other unusual conditions from consideration. The drafting team explained that it would not be prudent to simply ignore operations that occurred during large storms. Further, the Sanction Guidelines of the North American Electric Reliability Corporation allows the entity to be afforded more time for unusual events.

Organization	Yes or No	Question 1 Comment
Western Small Entity Comment Group	No	The comment group is concerned with the use of the phrase “slower than intended” in definition 4. The actual intended speed of operation is/was in the mind of the protection engineer who may not necessarily be available to testify regarding his intent for every fault. Settings documentation generally does not show speed of operation, only set points and manufacturer curves. A speed of operation may be derived from these settings right down to the millisecond, but the protection engineer did likely count on this level of precision after considering CT and relay measurement error and coordinating margin. Lacking a tolerance, the documented settings do not fully show the “intent.” In addition the documentation itself may be in error and possibly be the cause of a misoperation (although not by this definition if we use the document to gage intent). Entities and Compliance Enforcement will need more guidance from the drafting team on just how to measure “slower than intended”, and to understand just how slow that is. In the end, however, it is not the intended speed that matters, it is the result. The parenthetical suggests it is the result that counts, but we don’t see the parenthetical overruling the “slower than intended” language. Slow Trip - During Fault - A slow Protection System

Organization	Yes or No	Question 1 Comment
		operation for a Fault within the zone it is designed to protect, resulting in miscoordination with other Protection Systems or failure to meet the performance requirements of the TPL standards.
Response: Thank you for your comments. **The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate. The parenthetical phrases are part of the definition and meant to clarify parts of the definition. The parentheses will be removed so that these phrases are not seen as subordinate to other parts of the definition. The suggested change to part 3 of the definition changes the meaning by overstating the intent of the exclusionary phrases. This would weaken the language and allow the failure of certain required high-speed Protection Systems to be not classified as a Misoperation.**		
Pepco Holdings Inc & Affiliates	No	The existing definition of misoperation in the NERC Glossary of Terms indicates that if any individual component of a Protection System fails it is considered a misoperation. This new PRC-004-3 proposed definition modifies the definition by treating the primary and back-up protection schemes protecting a circuit element as a composite protective system. Individual component failures would not be considered a misoperation if the "overall performance of the composite Protective System for an element is correct." We support this intent, but feel that the present wording in the proposed misoperation definition is not clear enough to adequately emphasize this distinction. The capitalized term Protection System, which is a NERC defined term, is used throughout this standard. However, the applicability of the proposed misoperation definition applies to the "Composite Protective System", and not to each of the primary and backup Protection Systems individually. This point must be made very clear in the misoperation definition, since it is the foundation of the

Organization	Yes or No	Question 1 Comment
		requirements in PRC-003-4. As such, either a new term "Composite Protective System" needs to be defined and the language in the misoperation definition and PRC-004-3 changed to reference this term; OR a qualifying paragraph could be included within the misoperation definition that states that "In the context of this misoperation definition a Protective System is considered to be the entire complement of protective system components (including both primary and backup protection systems) designed to protect a circuit Element."
Response: Thank you for your comments. **It is preferable not to add more definitions to the NERC Glossary of Terms, instead the drafting team modified the Guidelines and Technical Basis section to include the following: "The composite Protection System in the context of this standard is the total complement of protection for a system Element (line, bus, transformer, generator, etc). Primary and secondary protection of a given Element is considered as the composite Protection System, not two separate Protection Systems." The drafting team also changed the introductory sentence of the definition to the following based on your comment: "The failure of an Element's composite Protection System to operate as intended."**		
Souhwest Power Pool Reliability Standards Development Team	No	We need some clarification around section 3 Slow Trip During Fault. Is this intended to address the future changes around the Upcoming TPL standards? We need clarification on what is meant by referencing the TPL performance Standards in this section.
Response: Thank you for your comments. **No, the reference to the TPL standards is not related to the upcoming changes to these standards. The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability.**		
Detroit Edison	No	No, Dteroit Edison disagrees with "Slow Trip - Other than Fault." We feel that the SDT should consider, with respect to many of the Generating Unit trip conditions that are given, that there may not be adequate resolution of time and current\voltage\etc. monitoring. If monitoring with as fine a

Organization	Yes or No	Question 1 Comment
		resolution as is required to analyze speed of operation, it should not be considered a misoperation.
Response: Thank you for your comments. **The standard and Misoperation definition do not require any additional monitoring be installed. Each entity must review each of its Protection System operations and determine whether the operation should be categorized as a slow trip - other than Fault Misoperation based on its available information.**		
Tacoma Power	No	1) It is still not completely clear what is meant by 'intended'? 2) The wording for Slow Trip - During Fault is awkward. For example, consider changing "...if high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems" to "...if high-speed performance is required to meet the performance requirements of the TPL standards or coordination requirements with other Protection Systems"; in other words, remove 'by.' 3) Under the proposed, revised definition of a Mis-operation, it is unclear if a Mis-operation resulting from mis-coordinated relays would normally be categorized as Slow Trip or Unnecessary Trip. 4) What is meant by 'on-site,' as in the definition of Unnecessary Trip - Other Than Fault? Specifically, what if a remote terminal is inadvertantly tripped by means of a communications system during maintenance, testing, construction, or commissioning activities; technically, the interrupting device that operated is not "on-site." 5) Additionally, what if an operation occurs during initial energization or loading following maintenance, testing, constuction, or commissioning; it seems that because the operation occurs with personnel still on site that this should not be considered a reportable Mis-operation, especially since

Organization	Yes or No	Question 1 Comment
		the Element is just being returned to service.

Response: Thank you for your comments.

1) The word "intended" as used in the definition refers to whether the Protection System performance met the objectives of the owner(s).

2) Removing the word "by" does not improve the wording. If the word "by" is removed, other wording would need to be changed. An alternative could be the following: "…if high-speed performance is required to meet the performance requirements of the TPL standards or to coordinate with other Protection Systems."

3) It depends on the miscoordination. If the Misoperation occurred because the Protection System for the faulted Element operated slower than intended, then it is a Slow Trip – During Fault. If the Misoperation occurred because a Protection System for another Element operated faster than intended, then it is an Unnecessary Trip – During Fault.

4) "On-site" refers to on-going activities at BES Facilities. This is the opposite of "as left" conditions where some activities were completed and personnel left the Facilities. The inadvertent operation to a remote terminal via communications would be the result of an "on-site" activity.

5) Once the equipment has been returned or released to service, or the inspection has been completed, it would be considered a Misoperation regardless of the presence of the technical personnel.

Organization	Yes or No	Question 1 Comment
Santee Cooper	No	While the purpose of the clarifications in the misoperation definition is understood, the proposed definition seems to use the term "non-fault condition" differently in different sections. For items 2 and 4, it says "a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, overexcitation, or loss-of-excitation." Similar wording is used in 4 "such as a power swing, under-voltage, overexcitation, or loss-of-excitation. However, in 6, the terms "other than fault" and "non-fault condition" are also used, but, it would be expected that the definition here should be broader than in 2 and 4, to include when a misoperation occurs for no reason (no abnormal condition). It seems like this could lead to a misinterpretation of number 6, since it uses the same

Organization	Yes or No	Question 1 Comment
		term “non-fault condition” as in 2 and 4.We suggest having the following 4 categories, which would still ensure that the “non-fault conditions” are still included:1. Failure to Trip - A failure of a Protection System to operate for a Fault within the zone it is designed to protect or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System was intended to operate.2. Slow Trip - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect or for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation.3. Unnecessary Trip - A Protection System operation for a Fault or for a non-fault condition (such as a power swing, under-voltage, over excitation, or loss of excitation) for which the Protection System is not intended to operate. This excludes any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.4. Unnecessary Trip - Normal system conditions - A Protection System operation when no fault or non-fault conditions are present (such as a power swing, under-voltage, over excitation, or loss of excitation).There may be other appropriate wordings for number 4.
Response: Thank you for your suggestion. **The drafting team believes the non-Fault condition phrase is used consistently in categories 2, 4, and 6. The non-Fault conditions cited in categories 2 and 4 are examples and do not constitute an all inclusive list.**		
Dominion	No	a). Under Definitions of Terms Used in the Standard, #3 indicates that delayed clearing of a high speed protection system is a Misoperation if it does not meet TPL requirements or coordination requirements. The specific requirements being referred to are unclear and non specific. Is the intent to report failure of high speed tripping for those Protection Systems that impact system stability? Suggest that more clarity be given to the requirement references.

Organization	Yes or No	Question 1 Comment
		b). Under Definitions of Terms Used in the Standard, #5 change definition to read - Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding properly coordinated remote trips when the local Protection System fails to clear the Fault. c). In the Application Guide - Guidelines and Technical Basis, under the definitions there appears to be more emphasis on Generation related examples. Recommend a balance of both Generation and Transmission examples in this guide.
Response: Thank you for your comments. **a) The performance requirements in the TPL standards are found in Table 1. While system stability is often the primary concern, there are thermal and voltage limits and loss of Demand impacts that need to be met as well. The coordination requirements with other Protection Systems does not refer to requirements listed in standards but the need to ensure that relaying operates in the proper or planned sequence (i.e. the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).** **b) The drafting team modified category 5 of the definition and believes it addresses your concern.** **c) A review of the examples shows that they are evenly split between Generation and Transmission examples. Categories 2 and 4 of the definition which involve failure to trip and slow trip during non-Fault conditions are somewhat more relevant to generators as line and transformer protection is predominately for detecting Faults.**		
Luminant	No	Misoperations categorized in line items #3 and #4 are subjective and left up to varying interpretation for protective systems on generator applications. Unlike the definition for “Slow Trip - During Fault”, Transmission Owners are provided with criteria that define a slow operation while generation owners do not have similar established criteria for trips involved in items #3 or #4. Luminant recommends line item #4 be removed since it is subject to varying interpretations and item #3 be only applicable to Transmission.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **The drafting team does not believe that categories 3 and 4 are subjective. It is true that entities will have varying capabilities in determining whether an operation was slow or not but that is not a subjective issue. The standard and Misoperation definition do not require any additional monitoring to be installed. Each entity must review each of its Protection System operations and determine whether an operation is a Misoperation based on the available information. The drafting team believes that it does not serve the interest of BES reliability by basing analysis capabilities on the minimum monitoring that any entity may have at its disposal. The criteria for category 3 are also applicable to Generation Owners. In particular, the Protection Systems for a generation Facility need to coordinate with other Protection Systems. The phrase “slower than intended” in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate. The drafting team will enhance the Guidelines and Technical Basis section with this information.**		
Florida Municipal Power Agency	No	1) The description of “unnecessary trip”, the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not “unnecessary”) and it is intended to operate for failure or slow operation of local Protection Systems. 2) The description for a remote back-up system operation and limimting that to only the “adjacent” zone is not appropriate. There are cases when the appropriate protection system operation may not be from the “adjacent” zone of protection. 3) Also, the term “zone of protection” is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different “zones of protection”. If a zone 3 relay covers two transmission facilities, is that one and the same “zone of protection”? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc.

Organization	Yes or No	Question 1 Comment
		4) The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
Response: Thank you for your comments. **1) The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.** **2) The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.** **3) The term "zone of protection" is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the "IEEE Guide for Protective Relay Applications to Transmission Lines", IEEE Std C37.113-1999 (or later revisions if available).** **4) The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Duke Energy	No	Duke Energy does not agree with the wording in Part 3 of the definition of Misoperation. "3. Slow Trip - During Fault" identifies "Delayed Fault clearing associated with an installed high speed protection scheme" as a Misoperation, "if the high-speed performance is required to meet the performance requirements of the TPL standards". The TPL standards do not currently contain any high-speed performance requirements, and Transmission Planners must plan to meet Category C "Single Line to Ground Faults" with delayed clearing. We suggest the following alternative wording which removes the linkage to TPL standards, and puts "3. Slow Trip - During

Organization	Yes or No	Question 1 Comment
		Fault" on the same footing as "1. Failure to Trip - During Fault" and "2. Failure to Trip - Other Than Fault":"3. Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation as long as the overall performance of the Protection System for an Element is acceptable, and the high-speed performance is not required for coordination with other Protection Systems.)
Response: Thank you for your comments. **The drafting team disagrees with your suggested wording because there is no indication as to what is considered acceptable performance. The performance requirements in the TPL standards are found in Table 1 are applicable to all contingencies mentioned for Type A, B and C contingencies and state: System Stable and both Thermal and Voltage Limits within Applicable Rating Specifically, the performance requirements are dynamic performance requirements and are typically met by requiring installation of high-speed protection.**		
JEA	No	JEA suggests a shorter definition such as: either the operation of a protection system when it should not or the failure to operate when it should.
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous. For example, by using the word "when" it is not clear whether an operation is a Misoperation if it was slow or just whether it did or didn't operate. The proposed definition also provides none of the specific exceptions that have been cited in the 6 categories. Unfortunately, the brief definition leaves it open to interpretations because of its lack of detail.**		
Nebraska Public Power District	No	I recommend adding the underlined text to the misoperation definitions for items: Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection

Organization	Yes or No	Question 1 Comment
		scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection systems for a reasonable number of system contingencies. Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate for a reasonable number of system contingencies, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone. Perhaps the number of contingencies should be a set number such as one so that for non standard system configurations where coordination may be lost. For example, such as multiple ground sources being out of service causing ground overcurrent miscoordination in part of the system.
Response: Thank you for your comments. **Unfortunately, a "reasonable number of system contingencies" is ambiguous and its use in the standards would complicate enforcement. It would also be difficult to decide on a single number that would be appropriate for all cases.**		
Southern Company	No	1) Instead of clarification and specification, the objective of the change to the definition should be simplification. A simpler definition could be: Failure of a Protection System to operate as intended, evidenced by it not operating when it should have, operating when it should not have, or operating slower than it was intended to operate. 2) If the definition remains in the present form, we would suggest slight changes to language on #1 and #2: (The failure of........of the Protection System for the element it is designed to protect is correct.) 3) Suggest slight changes to language on #3: (Delayed Fault clearing ....high-speed performance has been identified as required......) 4) Please clarify why # 3 and # 4 are not a subset of # 1.If not, it should be

Organization	Yes or No	Question 1 Comment
		made clear in the verbiage.
Response: Thank you for your comments. 1) **Although a shorter definition has many advantages, it has significant shortfalls. For example, by using the word "when" it is not clear whether an operation is a Misoperation if it was slow or just whether it did or didn't operate. The proposed definition also provides none of the specific exceptions that have been cited in the 6 categories. Unfortunately, the brief definition leaves it open to interpretations because of its lack of detail.** 2) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 3) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 4) **Categories 3 and 4 are slow trips, not a failure to trip. For example, the local Protection System may have operated and initiated a trip but not before a remote Protection System operated. Also category 4 is for a non-Fault condition where category 1 is specifically for a Fault condition.**		
ITC	No	1) For 1 through 3, The definitions should be revised to remove the need for the clarifications in parenthesis. One such revision should include clarifying the scope of a 'Protection System.' It is not clear whether multiple protection schemes for a single element would be considered one 'Protection System' or if each scheme is considered a 'Protection System'. It may require clarifying the definition of 'Protection System' within NERC Glossary or addressing directly in this standard. 2) What is the definition of 'slow?' Is it only defined by TPL standards or expected operation time designed into the 'Protection System?'
Response: Thank you for your comments. 1) **The parentheses have been removed per comments received. The drafting team changed the introductory sentence of the definition to the following based on comments and should address the multiple schemes issue that you brought up: "The failure of an Element's composite Protection System to operate as intended."** 2) **The term "slow" is not defined in this or the TPL standards or the NERC Glossary of Terms. In the definition, it is stated that**		

Organization	Yes or No	Question 1 Comment
"…operation that is slower than intended…" The phrase "slower than intended" means that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
Cleco Corporation	No	Need clarification on what is meant by referencing the TPL performance standards in section 3.
Response: Thank you for your comment. The reference to the TPL standards is meant to place some bounds on the time to clear a Fault. The performance requirements in the TPL standards are found in Table 1 are applicable to all contingencies mentioned for Type A, B and C contingencies and state: System Stable and both Thermal and Voltage Limits within Applicable Rating Specifically, the performance requirements are dynamic performance requirements and are typically met by requiring installation of high-speed protection.		
Manitoba Hydro	No	1) Although we agree with most components of the definition, it is not clear to us what constitutes a "Failure to Trip". For example, in cases of redundant "A" and "B" protection systems, if the "A" protection trips, but the "B" protection does not trip, would this be a misoperation reportable as a "Failure to Trip"? 2) The first sentence of the second last paragraph of section A is not clear:"Misoperation of or associated with Special Portection schemes ...."
Response: Thank you for your comments. 1) No, because there is redundancy in the composite Protection System, the overall performance would not be impacted. 2) The sentence is simply indicating that the Misoperations of SPSs, RASs and UVLSs are not addressed in this version of the standard.		

Organization	Yes or No	Question 1 Comment
Tri-State G&T	No	1) We understand why the parenthetical expressions are included in the first two parts of the definition since they clarify what is excluded from the definition. However, the parenthetical phrase in the third part of the definition seems to be another expression of what is to be considered a Misoperation, but it is not consistent with the non-parenthetical definition. We suggest changing it to “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance is not used to meet the performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.” 2) We have a question regarding the phrasing “required to meet the performance requirements of the TPL standards” (changed in our recommended language). Does this mean that a simulation has been performed that determines that high speed protection is required to meet TPL standard requirements? Or does it apply to the slower clearing if the reduced performance results in a failure to meet the requirements of the TPL standards regardless of whether it had been discovered and documented? 3) While we did not base our “No” answer on the following, our belief is that the exclusions of individual Protection System component failures as long as the total Protection System operates to clear the Fault in the time and zone for which it was designed may lead to a reduced level of reliability to the BES. Failures of components may be easily overlooked if the entity doesn’t review the event closely enough to discover misoperating components because the aggregate system operated correctly. But we recognize that there is unclarity regarding the definition of Protection System and that unclarity could lead to considering the overall performance of the aggregate Protection System, which was the interpretation used by the drafting team.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **1) The drafting team made the suggested change to promote consistency in the definition.** **2) The drafting team revised Category 3 based on comments to clarify that high-speed performance has been identified.** **3) The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it.**		
Flathead Electric Cooperative, Inc.	No	We are concerned about what "Slow" is and if the drafting committee is creating a new kind of misoperation or whether this is something that might just be found as a result an investigation of an existing type of misoperation.
Response: Thank you for your comments. **The IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' developed categories of Relay System Misoperation including "Slow Trip" in 1999. Most of the Regional Entities did have a category of Misoperation called "Slow Trip." So, the terminology has existed for some time. All Misoperations require some amount of investigation. It is also likely that some investigation would be required to determine, for example, if the local protection was slow or the remote protection tripped unnecessarily (because it was too fast or did not receive a blocking signal, etc.).**		
Dairyland Power Cooperative	No	The SDT should clarify whether UFLS is or is not covered by this standard. The "Consideration of Comments" indicates that it is. If so, it is suggested that the SDT consider adding underfrequency to the list of non-Fault conditions listed in items 2. and 4. in the Misoperation definition. If not, it would help to clearly state that it is "excluded" in Section 4.2.2.
Response: Thank you for your comments. **UFLS that trip the BES are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities**		

Organization	Yes or No	Question 1 Comment
portion of the Applicability section 4.2.2 in the draft standard "Underfrequency Load Shedding (UFLS) that trips a BES Element". UFLS events can be triggered by Faults or non-Fault conditions. Not all non-Fault conditions are (or probably could be listed) with the examples in categories 2 and 4 of the Misoperation definition.		
MISO	No	The SDT should clarify whether UFLS is or is not covered by this standard.
Response: Thank you for your comments. **UFLS that trip the BES are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard "Underfrequency Load Shedding (UFLS) that trips a BES Element". UFLS events can be triggered by Faults or non-Fault conditions. Not all non-Fault conditions are (or probably could be listed) with the examples in categories 2 and 4 of the Misoperation definition.**		
City of Austin dba Austin Energy	No	The parenthetical at the end of the two "Failure to Trip" categories is not clear. Austin Energy requests the SDT to consider including some of the detail in the Guidelines and Technical Basis section on page 15 of the clean draft.
Response: Thank you for your comments. **The parentheses were removed and the language was further modified for clarity. The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. The drafting team believes the Applications Guide section is the proper location to document drafting team intent.**		
Texas Reliability Entity	No	(1) Failure to Trip During Fault: The statement "(The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct.) " is somewhat vague and open to interpretation. We understand the purpose of this language as stated in the Guidelines and Technical Basis, i.e. when a high speed zone element trips faster than a high speed pilot system. However, we have had instances in our Region where a high speed pilot system fails and the fault is subsequently cleared by a time-delayed zone

Organization	Yes or No	Question 1 Comment
		element, typically in 30-45 cycles rather than in 5 cycles or less. This instance could be interpreted as "correct overall performance" by the entity and not reportable. Is this the intent of the SDT? Or should this instance be recorded as a "Failure to Trip" or "Slow Trip During Fault"? The Guidelines and Technical Basis section offers some good examples, however, it should possibly be expanded to provide more discrete cases.(2) Failure to Trip Other than Fault: See comments under Failure to Trip During Fault(3) Slow Trip During Fault: See comments under Failure to Trip During Fault
Response: Thank you for your comments. **The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it. For the example cited, it appears that the operation would not be a Misoperation unless high-speed performance (as stated in category 3 of the definition) was required. If high-speed performance was required, then it would be an instance of "Slow Trip – During Fault".**		
Liberty Electric Power LLC	No	The "unnecessary trip- other than fault" should be removed. Standards should not cover balance of plant issues, which could be trip causes. While trip analysis is a best practice, it should not be a required, zero tolerance element of the NERC standards. For example, a turbine vibration fault could use the same 86 relay as the generator protection relay, which would make that 86 part of the protection system. Vibration trips of that 86 relay would then fall under the program, causing unneeded effort for compliance documentation of a straightforward balance of plant issue. The definitions themselves are overly complex, and could be combined in many cases.
Response: Thank you for your comments. **The drafting team Believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that**		

Organization	Yes or No	Question 1 Comment
occur during non-fault conditions. Excluding this type of Misoperation would cause a reliability gap. PRC-004-3 requires any Protection System operation be reviewed to determine whether the Protection System operated as intended to isolate the generating unit from the BES. The activation of the vibration sensor is not required to be reviewed because only protective relays that respond to electrical quantities are included in the "Protection System" as defined in the NERC Glossary of Terms.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	1) The description of "unnecessary trip", the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not "unnecessary") and it is intended to operate for failure or slow operation of Local Protection Systems. 2) The description for a remote back-up system operation and limiting that to only the "adjacent" zone is not appropriate. There are cases when the appropriate protection system operation may not be from the "adjacent" zone of protection. 3) Also, the term "zone of protection" is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different "zones of protection". If a zone 3 relay covers two transmission facilities, is that one and the same "zone of protection"? Or does the SDT intend a zone to be breaker-to-breaker? How is a Circuit Switcher treated when defining a zone of protection>? Etc. 4) The description of a "slow trip" as "operation slower than intended" without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.
Response: Thank you for your comments. **1) The point the exclusion in category 5 was making is that the remote operation was necessary and, therefore, should not be consider a Misoperation. However, it would be clearer if this item was broken into two sentences to better emphasize your concern. The exclusionary phrase has been replaced with the following second sentence: "The operation of a remote**		

Organization	Yes or No	Question 1 Comment
Protection System is not a Misoperation if it operated as intended as a result of an interrupting device failure, or a failure to trip, or slow trip of a local Protection System for a faulted Element." **2) The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.** **3) The term "zone of protection" is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the "IEEE Guide for Protective Relay Applications to Transmission Lines", IEEE Std C37.113-1999 (or later revisions if available).** **4) The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Consumers Energy	No	Protection Systems can be and are designed to provide remote backup protection for adjacent zones. In many instances, these zones are owned and operated by other entities. As worded, part 1 of the definition says "failure...to operate for a Fault within the zone it is designed to protect." If entity A has a Protection System that is designed to provide remote backup protection for entity B and entity B has a Fault on that Element, but does not notify entity A of said Fault, then without an interrupting device operation, entity A has no way of knowing if their Protection System should have operated or not.Proposed solution: Failure to Trip - During Fault - A failure of a Protection System to operate for a Fault within the zone it is designed to be the primary protection.
Response: Thank you for your comments. **The failure to trip of remote backup protection would be expected to result in a cascading outage or in equipment damage. PRC-004-3 would require the Protection System operations to be investigated by the owners, and would require the Misoperations to be mitigated. Excluding remote backup protection from PRC-004-3 would introduce a reliability gap. In your example, entity A**		

Organization	Yes or No	Question 1 Comment
would not be required to investigate the operation since they did not have an interrupting device operation unless entity B or some other entity notified them of a suspected Misoperation (see Requirement R1 part 1.1).		
Cogentrix Energy, LLC	No	The proposed definitions are unneccisarily complicated. Also, the "catch all" category "Unnecessary Tip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out.
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous. The drafting team believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that occur during non-fault conditions. Excluding this type of Misoperation would introduce a reliability gap.**		
CenterPoint Energy	No	CenterPoint Energy recommends additional clarification be included in Item 5 ‘Unnecessary Trip - During Fault’ to address interrupter device problems that result in what is commonly referred to as a “stuck breaker”. The proposed definition provides only for excluding remote tripping from a failure to trip or slow trip of a Protection System; however, interrupting device problems - other that trip coils - can also result in a failure to trip or slow trip event. Remote tripping is commonly utilized for local breaker failure schemes and for remote backup clearing for such stuck breaker events. CenterPoint Energy recommends adding wording at the end of Item 5, resulting in the following wording for ‘Unnecessary Trip - During Fault’: “A Protection System operation for a Fault for which the Protection System is not intended to operate, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone or from a failure to trip or slow trip of an interrupting device.”

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. **Category 5 of the definition was modified as follows and should address your comments: "Unnecessary Trip - During Fault - A Protection System operation for a Fault for which the Protection System is not intended to operate. The operation of a remote Protection System is not a Misoperation if it operated as intended as a result of an interrupting device failure, a failure to trip of a local Protection System or slow trip of a local Protection System for a faulted Element."**		
City of Tallahassee	No	The comment 'The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for an Element is correct' could be clearer. Perhaps stating 'The failure of a Protection System component is not a Misoperation as long as the Protection System operated for the fault within the zone it is designed to protect. Also, a distinction should be made whether a misoperation that only interrupts distribution and not transmission is a reportable misoperation. Example of what I am referring to is if a transformer relay trips a high side breaker but does not interrupt the BES, only distribution load.
Response: Thank you for your comments. **The exclusions of component failures as long as the total Protection System operates correctly were based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. The difficulty in requiring the investigation of component failures and the development and completion of associated CAPs is the additional administrative burden for a type of failure that had no immediate reliability impact for an event that revealed it. Section 4.2.1 of the Applicability section specifies that PRC-004-3 is applicable only to Protection Systems for Facilities that are part of the BES. PRC-004-3 is not applicable in the cited transformer relaying event because the transformer relay tripped only non-BES Elements.**		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).
Response: Please see the responses to comments by FMPA.		

Organization	Yes or No	Question 1 Comment
Tampa Electric Company	No	1) The description of “unnecessary trip”, the exclusion of remote protection System operation is not accurate because such operation is actually necessary (not “unnecessary”) and it is intended to operate for failure or slow operation of local Protection Systems. 2) The description for a remote back-up system operation and limimting that to only the “adjacent” zone is not appropriate. There are cases when the appropriate protection system operation may not be from the “adjacent” zone of protection. 3) Also, the term “zone of protection” is not defined, e.g., are zone 1, zone 2 and zone 3 distance relays different “zones of protection”. If a zone 3 relay covers two transmission facilities, is that one and the same “zone of protection”? Or does the SDT intend a zone to be breaker-to-breaker? How is a circuit swithcher treated when defining a zone of protection>? Etc. 4) The description of a “slow trip” as “operation slower than intended” without some sort of quantification of how much slower than intended is ambiguous (e.g., is one cycle longer delay than expected a misoperation?), unless the intent is to establish an operating time as the slowest intended operating time. Even so, measurability becomes a concern.

Response: Thank you for your comments.

1) **The drafting team revised category 5 of the Misoperation definition to remove mention of exclusions.**
2) **The drafting team agrees. In most cases a proper remote backup operation is in an adjacent zone. The language in Category 5 was changed to cover non-adjacent operations.**
3) **The term “zone of protection” is not used in the definition. This widely used term has been defined by other literature and does not require further clarification in this standard. A reference the commenter can use to clarify the term is the “IEEE Guide for Protective Relay Applications to Transmission Lines”, IEEE Std C37.113-1999 (or later revisions if available).**

Organization	Yes or No	Question 1 Comment
4) The phrase "slower than intended" in categories 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
Ameren Services	No	(1) We suggest, In #3 Slow Trip, to replace "or by coordination requirements with other Protection Systems" with "or to meet the coordination requirements with other Protection Systems in accordance with applicable PRC standards." For example, entities regularly install one pilot relaying system on a line for other reasons, such as end use power quality. The failure of such a pilot relaying system to trip high speed should not be classified as a Misoperation. (2) We suggest to insert "the operation" to clarify #6 yielding "Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the operation is unrelated to on-site maintenance, testing, construction or commissioning activities."
Response: Thank you for your comments. **1. The need to coordinate Protection Systems is not limited to requirements in the PRC standards. The drafting team does not believe there is a need to reference the PRC standards. The drafting team agrees with you that in the example you cite, a failure of the pilot relaying system would not be a Misoperation as it was not required to meet TPL performance requirements.** **2. The drafting team does not believe the insertion of the words "the operation" adds additional clarity to category 6.**		
Essential Power, LLC	No	1) The proposed definitions are unnecessarily complicated. 2) Also, the "catch all" category "Unnecessary Trip - Other Than Fault" will cause entities to analyze, document and report events that may occur but were not due to issues in engineering, design, or relay settings, thus

Organization	Yes or No	Question 1 Comment
		providing little to no benefit to industry to learn from the event. For example, a control wire that was chewed by a mouse and led to a line tripping out. 3) We would also like to see language that addresses an "Unnecessary Trip-During Fault - A Protection System operation for a Fault for which the Protection System is intended to operate, but operates prior to the required element setting."
Response: Thank you for your comments. **1) The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous.** **2) The drafting team believes "Unnecessary Trip - Other Than Fault" should be kept to capture Protection System Misoperations that occur during non-fault conditions. Excluding this type of Misoperation would introduce a reliability gap.** **3) The drafting team believes that the types of Misoperations that are included in the definition are sufficient. Assuming the drafting team is correcting interpreting what you are asking, an operation that occurs prior to an element setting may not be a Misoperation. If a remote Protection System operated for a Fault that should have been cleared by a local Protection System due to a coordination error at the remote terminal (set too fast), then it is an "Unnecessary Trip" at the remote location. If the coordination error was at the local terminal (set too slow), then it is a "Slow Trip" at the local location.**		
El Paso Electric	Yes	El Paso Electric Company (EPE) agrees with the definition with a slight change to the wording of the titles of "Failure to Trip - Other than Fault" and "Slow to Trip - Other than Fault". EPE believes in these applications the titles should read Failure to Operate - Other than Fault and Slow to Operate - Other than Fault. There are scenarios, in the case of a power swing, where a device or element may be set to block a trip.
Response: Thank you for your comments. **While the drafting team agrees with your logic and sentiment, we prefer to stay as close as possible to the legacy language used by the IEEE and several Regional Entities. The slight change could confuse many in the industry into thinking that new**		

Organization	Yes or No	Question 1 Comment
Misoperation types are being created.		
ACES Power Marketing Standards Collaborators	Yes	The definition and its rationale seem reasonable. One observation is to shorten the language of each category of Misoperations. Generally, detailed definitions cause more problems in compliance than short and concise definitions. We had one question for the SDT regarding the definition - is breaker failure considered a Misoperation?
Response: Thank you for your comments. **The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous and preventing interpretations due to lack of detail. The breaker excluding its trip coils is not part of a Protection System; so, if the breaker itself physically fails to interrupt current, that failure by itself is not a Misoperation. However, if breaker failure protection falsely operates unnecessarily tripping adjacent breakers, then this false operation is a Misoperation (either category 5 or 6 depending whether a Fault existed at the time).**		
Bonneville Power Administration	Yes	BPA thanks the drafting team for their efforts as this standard has improved significantly over the previous version. While BPA believes the standard is on the right track, clarification needs to be made to a few key area's listed throughout comments below. A fair number of inadvertent operations are caused by accidental jarring of a relay panel. Since the jarring might not be due to maintenance, testing, construction, or commissioning activities, it isn't clear if it should be excluded from the definition of a misoperation by item 6. BPA suggests adding "accidental jarring" to the exclusions in item 6.
Response: Thank you for your comment. **Inadvertent operations that occur due to on-site activity are included. However, the term "accidental jarring" is too non-specific. The drafting team added "inspection" to the list of activities in category 6.**		
Western Area Power Administration	Yes	The Applications Guidelines section of the proposed standard is invaluable in clarifying the requirements. We propose that some of this information

Organization	Yes or No	Question 1 Comment
		be directly added to the associated standards. This includes statements in items (2) and (6).
Response: Thank you for your comment. **The Guidelines and Technical Basis section provides specific examples to further clarify the definition and standard. The drafting team believes the existing definition sufficiently describes the term of Misoperation providing enough detail to be unambiguous and preventing interpretations due to lack of detail. The drafting team believes the Guidelines and Technical Basis section is the proper location to document drafting team intent.**		
Utility System Efficiencies, Inc.	Yes	This standard revision is solid and specific, and should be MUCH more straightforward to audit/enforce, since it specifically requires the analysis of all operations. A comment is needed concerning the lack of any exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Response: Thank you for your comments. **All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section, in the event of a natural disaster, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15,**		

Organization	Yes or No	Question 1 Comment
2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events.		
Idaho Power Co.	Yes	We believe the previous comment period has produced a thorough definition of a Misoperation.
Response: Thank you for your comment and support.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP believes that the modification is an improvement over the previous draft. However, we still would like to see a commitment from the ERO-Reliability Assessment and Performance Analysis (RAPA) Group that they will align their definition when PRC-004-3 takes effect. Although the differences are minor, a difference in the criteria may require the industry to make two separate determinations on whether a relay-related event should be identified as a Misoperation.
Response: Thank you for your comment. **The present Quarterly Misoperation Reporting Form is in a state of change as the NERC SPCS attempts to provide proper data for ALR4-1 metrics and PRC-004-3 requirements. Some changes cannot be made on the reporting form until the standard is formally approved. Until then, the drafting team will forward industry comments to the NERC SPCS so that the categories of the Misoperation definition included in Quarterly Misoperation Reporting Form agree with the definition of Misoperation included in the approved Reliability Standard PRC-004-3.**		
Exelon Corp.	Yes	1) Exelon would like to see stronger wording to very clearly state that the protection system is to be evaluated as a composite system (primary and backup are part of a single composite system). 2) Under the Misoperation definition section:a. Item 1 Failure to Trip - During Fault ... change “for an Element” to “for the Element”. 3) b. Item 2 Failure to Trip - Other Than Fault ... change “for an Element” to “for the Element”.

Organization	Yes or No	Question 1 Comment
		4) c. Item 6 "Unnecessary Trip - Other Than Fault" - needs more clarification as to whether or not this includes personnel error (e.g. open test switches inadvertently).
Response: Thank you for your comments. 1) **The drafting team changed the introductory sentence of the definition to the following based on comments and should address the multiple schemes issue that you brought up: "The failure of an Element's composite Protection System to operate as intended."** 2) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 3) **The drafting team agrees and believes the suggested change adds clarity, the definition was changed.** 4) **The drafting team believes the language "unrelated to on-site maintenance, testing, inspection, construction or commissioning activities" clearly indicates that "personnel error (e.g. open test switches inadvertently)" is excluded from consideration as a Misoperation as long as it is related to on-site activities. Once the equipment has been returned or released to service, or the inspection has been completed, it would be considered a Misoperation regardless of the presence of the technical personnel.**		
Independent Electricity System Operator	Yes	We agree with the definition intent to provided a distinction between protection systems intended to isolate faulted elements and protection systems intented to operate for other system conditions. For the latter category, we are concerned that listing the possible causes for the "other than fault" conditions may be interpreted as the only ones to watch for. Therefore we suggest that the definition should clarify that these possible conditions are not limited to those listed in the definition
Response: Thank you for your comments. **The drafting team believes that the words "such as" before the causes are adequate to indicate that these do not purport to be an all-inclusive list.**		
Orange and Rockland Utilities	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Company of New Mexico	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
PSEG	Yes	
Los Angeles Department of Water and Power	Yes	
Sacramento Municipal Utility District	Yes	
NextEra Energy Inc.	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
GTC	Yes	
ISO/RTO Standards Review Committee	Yes	
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
seattle city light	Yes	
Wisconsin Electric	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
American Electric Power	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
New York Power Authority	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Project 2010-05.1	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	Yes	
SERC Protection and Control Subcommittee (PCS)	Yes	

2. **Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, and designate each Misoperation. Do you agree with this approach? If you do not agree, please provide specific alternatives.**

Summary Consideration:

Several commenters asked to exclude major weather events and other unusual conditions from consideration as it may not be possible to analyze operations to determine Misoperations in the given timeframes. The drafting team explained that it would not be prudent to simply ignore operations that occurred during large storms. Further, the Sanction Guidelines of the North American Electric Reliability Corporation allows the entity to be afforded more time for unusual events.

Many commenters noted confusion in the requirements in Requirement R1 surrounding accountabilities of the Protection System owner and the owner of the interrupting device. The drafting team revised Requirement R1 to provide clarity in situations where the Protection System owner is also the interrupting device owner and in situations where there are multiple owners of Protection System components of a Protection System involved in a Misoperation.

Several commenters did not understand what the phrase "designate each Misoperation" was intended to mean. The drafting team replaced "designate each Misoperation" with "determine if it (the operation) was a correct operation or a Misoperation" in Requirement R1.

Several commenters expressed concern that BES interrupting device trips resulting from control actions, especially when that function found in a protection relay, is not explicitly excluded from PRC-004-3. Although this was noted in the Guidelines and Technical Basis of the draft standard and excluded in the Facilities section of the original posting, the drafting team revised Section 4.2.4 of the Facilities section of the standard to say "Non-protective functions that may be imbedded within a Protection System are excluded". The drafting team originally listed example functions but did not want to give the impression this list was all inclusive. Further clarity on this subject remains in the Guidelines and Technical Basis.

Several commenters questioned the reasoning in Requirement R1 on why all Protection System operations need to be reviewed and found the requirement to be unnecessarily onerous. The drafting team declined to make the recommended change to because reviews of all Protection System operations are important to ensure all portions of the protection scheme are functioning as intended and to confirm that the operation was correct.

A few commenters questioned what constituted a Protection System "review" of operations of interrupting devices. The drafting team is not being prescriptive about what a Protection System operation review entails. It is left to the entity to determine what method is used to perform and document the review for the purpose of classifying an operation as normal operation or Misoperation.

A few commenters expressed concern about the 120 day timeframe to review Protection System operations. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations as well as outage constraints for investigative purposes. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

A few commenters noted that the focus of PRC-004-3 should be on a standard that emphasizes internal controls over an entity's process rather than actual work execution. The drafting team declined to make this change and believes the current approach meets the reliability objectives established in the SAR for this project.

Several commenters had concerns that the standard implied additional monitoring equipment must be installed. The drafting team responded with the following: The standard does not require any additional monitoring equipment to be installed. Each responsible entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.

A few commenters thought the Protection System owner should be accountable for reviewing the Protection System operation. The drafting team did make changes to R1 to reflect the intent that the owner of the BES interrupting device would be in the best position to initiate the investigation of that operation. If it was determined that another entity's Protection System component appeared to cause the Misoperation then the burden shifts to the owner of that component. R1 was re-written to ensure this was clear.

One commenter was concerned that an entity can transmit information regarding a Misoperation but cannot force a response from the entity they sent the information to. The drafting team agreed and re-worded Measure M1 to read "Acceptable evidence for the notification required by Requirement R1, Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information."

One commenter expressed concern about being able to prove it identified all BES Protection System operations. As indicated in Measure M1, an entity may use any number of means to prove it has logged interrupting device operations and the drafting team believes most entities are already saving this information.

One commenter requested clarity be provided in the rationale box for Requirement R1, that the interrupting device owner is responsible for initiating an investigation. The drafting team added the following statement to the rationale box for Requirement R1: "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System."

A few commenters asked whether a single CAP or action plan can address multiple similar Misoperations. The drafting team believes that a single CAP or action plan can address multiple similar events.

One commenter requested that Requirement R1 be clarified by adding "unplanned" to "Within 120 days of an interrupting device operation. The drafting team pointed out that this exception is provided in the definition of Misoperations and is also referenced in the Guidelines and Technical Basis section for category 6 of the Misoperations definition. It states: "Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, inspection, construction or commissioning."

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Northeast Power Coordinating Council</td><td>No</td><td>1. Requirement R1 (as well as the other Requirements in the Standard) should be formatted to start with "Each...". For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do.
2. The use of the words "in its Facility" should be changed to reflect what is being protected. Suggested wording for consideration:R1. Each Transmission Owner, Generator Owner, and Distribution Provider within 120 calendar days of a Protection System Misoperation initiating an interrupting device operation in its system shall have and implement a procedure to identify and address all Protection System Misoperations within its system.
3. Closure is also needed in the procedure to ensure a definitive corrective response to a misoperation to prevent its recurrence.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The drafting team made the suggested change.
2. The term Facility is a defined term in the NERC Glossary of Terms and captures the intent of the drafting team.
3. The closure is covered by Requirements R2 and R4 with the development and implementation of the CAP.</td></tr>
<tr><td>Western Small Entity Comment Group</td><td>No</td><td>The comment group does not agree that every operation needs to be reviewed; only those that are clearly misoperations or are suspected to be misoperations should</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		need to be reviewed. Reviewing and documenting the review of proper operations provides no reliability benefit and may cause a detriment to reliability by directing resources away from where they might make a difference.
Response: Thank you for your comments. **The drafting team believes all Protection System operations must be reviewed to ensure Misoperations are identified. The drafting team further believes the review of all operations is required to ensure that all portions of the protection scheme are functioning as intended, and because Misoperations are sometimes not obvious or "clear".**		
Pepco Holdings Inc & Affiliates	No	1. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. The one who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO's breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for also reviewing all GO protection initiated trips because the TO owns the interrupting device. This is unreasonable. The party who owns the Protective System(s) that protect the BES facility that was interrupted should be the one responsible for reviewing those Protective System operations and for developing any appropriate corrective action plans. Because of compliance implications the standard must make a very clear division of compliance responsibilities between the parties when interconnected Protective Systems are involved. The owner of the Protective System(s) that initiated the trip of the BES facility should be the one responsible for reviewing the operation for correctness (R1). The owner of the Protective System(s) whose misoperation led to the interruption of a BES Facility should be the one responsible for identifying the cause and developing and implementing a corrective action plan (R2, R3, and R4). To make this perfectly clear we suggest re-wording

Organization	Yes or No	Question 2 Comment
		Requirements R1, R2, R3, and R4 as follows:R1. Within 120 calendar days of an operation of an interrupting device which interrupts a BES Facility that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which protects the BES Facility that was interrupted shall: ...R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall...R3. For each misoperation without an identified cause(s), the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall...R4. For each CAP or action plan, the Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall.... 2. What does R1.2 “Designate each misoperation” mean? Perhaps a more descriptive phrase would be “Designate which operations involve a Protective System Misoperation” OR “Identify and document each Protective System Misoperation”.
Response: Thank you for your comments. **1) The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **2) The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Souhwest Power Pool Reliability Standards Development Team	No	We would like some clarification on the review identified in R1. Based on the type of review that 120 days may or may not be enough time. We would request some example(s) be added in the Guidelines and technical reference that outline what is meant for the review in R1. Based on the examples the drafting team develops we can determine if the 120 days is appropriate. We also don’t agree that 120 days is enough time for those instances when major disturbances IE storms hurricanes tornadoes. This needs to be addressed in the requirement itself and would request that there be an extension that could be requested for those types of events

Organization	Yes or No	Question 2 Comment
		reported in DOE 417 and EOP 004.
Response: Thank you for your comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
El Paso Electric	No	EPE believes more clarity is needed in this requirement as to responses required by other owners when their component may have contributed to the misoperation of the Protection System. For example, Entity A's protection system operates, however Entity B's component contributed to the misoperation. Entity A notifies Entity B of such component failure. There isn't a specified timeline, within the 120 days, requiring Entity B to notify Entity A of its information regarding such component, allowing Entity A to timely complete its analysis and report of the operation of its Protection System. Additionally, what would Entity A's response be if Entity B doesn't acknowledge their component's contribution to the misoperation?
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The new Requirement R1 requires notification of all Protection System component owners (entity B in your example). There is no further action required by entity A in your example.**		
SERC Protection and Control Subcommittee (PCS)	No	1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "...such as when a reverse power

Organization	Yes or No	Question 2 Comment
		relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. 2) Clarify the Rationale consistent with Technical Basis page 17, by clearly stating that "the interrupting device owner is responsible to investigate operations initiated by a Protection System." 3) Augment the Rationale by adding at the end, "...and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information." A fair number of Misoperations trip another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but, once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction. 4) Change R1 1.2 to "Designate each operation as correct or a Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps." IEEE 1366 defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.

Response: Thank you for your comments.

1. **The Guidelines and Technical Basis section of the standard supplies the drafting team's reasoning and basis for writing the requirements. Consequently, the Guidelines and Technical Basis section provides background information for auditors and those responsible for implementing the standard. The Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section.**

Organization	Yes or No	Question 2 Comment
The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device. **2. The SDT agrees. Wording has been changed in the rationale box for clarity.** **3. The reporting obligations have been removed from the standard.** **4. The drafting team revised Requirement R1. Please review the new Requirement R1. The drafting team believes that a single CAP or action plan can address multiple similar events.**		
ACES Power Marketing Standards Collaborators	No	There is not a NERC glossary term for "interrupting device." The SDT should consider proposing a new glossary term to clarify what Protection System equipment is included in order to properly analyze all applicable equipment. Does the SDT intend interrupting devices to include switching equipment capable of interrupting a fault or would the team also include switching equipment capable of interrupting load? This term could include more than is intended and additional clarity is needed.
Response: Thank you for your comments. **For purposes of this standard, the drafting team intends "interrupting devices" to include circuit breakers and circuit switchers. The drafting team does not believe it is necessary to add this term to the NERC Glossary of Terms but will add this language to the Guidelines and Technical Basis section of the standard.**		
Colorado Springs Utilities	No	The way R1 currently reads, investigations would be required for planned work (e.g., full function trip testing). Language should be "Within 120 calendar days of an unplanned interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall:". The "unplanned" should apply to the interrupting device operation, vice Protection System operation, so that an investigation is required for misoperations during testing.
Response: Thank you for your comments. **This exception is provided in the definition of Misoperations in the standard and is also referenced in the Guidelines and Technical**		

Organization	Yes or No	Question 2 Comment
Basis section for category 6 of the Misoperations definition. It states: "Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning."		
Florida Municipal Power Agency	No	1. The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. FMPA is not in favor of a zero defect approach especially when most relay operations operate correctly. FMPA recommends usin g approaches similar to what the COM-003 and CIP v5 teams are considering. 2. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3. In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was "slow" or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence? It would seem to FMPA that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. **1. The standard is worded very specifically to ensure that the operation of an interrupting device triggers the beginning of an investigation. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.** **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **3. The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than**		

Organization	Yes or No	Question 2 Comment
the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
PPL Corporation NERC Registered Affiliates	No	The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. The SDT evidently meant to prevent this circumstance from posing an unwarranted burden by stating in the Application Guidelines that, "...in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." The line of demarcation between the protection and control functions of reverse power relays is not at all clear, however.We typically have for example a primary reverse power relay that trips the breaker 3 seconds after detection of motoring if all MS and HRH valves are indicating closed, and 27 seconds later regardless of valve position if it is not already offline, plus a backup relay that acts one minute after the start of motoring regardless of valve position. We take the 3-sec action as being a control function, while the other timers are protective in nature. What they protect is the low-pressure turbines from windage (high temperature) damage, however, not the generator. The reverse power function is consequently in the same class as a low lube oil pressure switch, and should not be in the scope of Protection Systems.PRC-004-3 as presently written though appears to require analysis of every reverse power trip that is not caused by the 3-second function described above, which may occur quite often given that valve position indicators are not high-reliability instruments. Each such investigation would involve documenting the, "sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records," for each normal stop (ref. the

Organization	Yes or No	Question 2 Comment
		"Requirement R1" section of the Application Guidelines) and determining whether or not the Protection System operation was slower than expected (ref. items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO's standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (inappropriately, we believe) as being part of the Protection System, but these devices do not trip in response to something having gone wrong, nor do they protect the generator. It is intended that negative current be experienced at some point as the unit unloads; and subsequent actuation of the reverse power relay is normal, expected and a mechanical (turbine) protection function. Requirement R1 and to the Application Guidelines should be modified to state that investigation of reverse power relay events is not part of the Protection System and PRC-004-3 consequently does not apply to such devices or, alternatively, is required only if the relay failed to function.
Response: Thank you for your comments. **Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device. It is incorrect to equate the reverse power protection function with a low lube oil pressure switch. The latter is excluded because it operates on a non-electrical quantity whereas the former operates on an electrical quantity. These longer delayed reverse power functions are not considered a control function and so do not come under that exclusion.**		
Bonneville Power Administration	No	BPA believes requirement R1 needs to provide more clarity about which entity is required to review a protection system operation. R1 requires TO's, GO's, and DP's

Organization	Yes or No	Question 2 Comment
		to review the protection system operation for an “interrupting device operation in its Facility”. This is not necessarily the same thing as the owner of the interrupting device, which is who the Application Guidelines places the responsibility on. The use of “Facility” seems inconsistent with the NERC definition of Facility: A set of electrical equipment that operates as a single BES Element. It is not clear what “in its Facility” means. The SDT appears to be using “Facility” in place of “substation”. The Rationale for R1 (blue box) mentions the owner of the interrupting device, but like R1, the rationale does not make it clear who is responsible for reviewing the protection system operation. It isn’t clear if the Rationale for R1 and the Application Guidelines are an official part of the standard, so while they might offer additional information, it is important that Requirement R1 can stand on its own and make it clear who is responsible to review the protection system operation. As presently written, BPA infers that this is not the case.Because the owner of the protective relays has the best access to the information that would be first reviewed, BPA believes that the owner of the protective relays should be required to initiate the review. From that initial review, the owner of the protective relays can then request information from other entities involved, if there are any, such as the owner of the communication system or the owner of the interrupting device. If there are different owners of the protective relays at the different terminals of an element, they should each initiate a review of their own protective relays.Requirements R2 and R3 are also unclear about who is responsible for fulfilling the requirement. Both of these specify the TO, GO, or DP as responsible for the requirement, but since there are often multiple TO’s, GO’s, or DP’s involved, which one is responsible? The Application Guideline for R2 specifies the protection system owner as being responsible. This information should be included in the Requirement itself, not just in the Application Guide.BPA believes that the owner(s) of the protection system component(s) that are identified as the cause of the misoperation in the review conducted per R1, should be responsible for R2. If there is no identified cause, the owner of the protective relay should be responsible for R3.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The closure is covered by Requirements R2 and R4 with the development and implementation of the CAP.**		
GTC	No	Rationale for R1: State that the interrupting device owner is responsible to investigate operations initiated by a Protection System, to be consistent with the Technical Basis. For Misoperations that occur when one entity's system trips another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. Under the present PRC-004-2a, there is confusion on this distinction.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
ISO/RTO Standards Review Committee	No	It is unclear on what "Designate each Misoperation" means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
JEA	No	It does not appear to be cost effective to identify and review each PS operation. Also, as time goes on and issues are found and resolved this standard becomes even less beneficial because of the ever decreasing percentage of misoperations that should result from the standard.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The drafting team believes that all Protection System operations must be reviewed to ensure all Misoperations are identified.		
TVA Transmission Operations and Maintenance	No	Comments: The requirement to review and document each Protection System Operation is overly burdensome to those utilities with heavy lightning exposure. TVA has approximately 400 interruptions a year due to lightning. To review, verify, and document each one of these to ensure whether or not a misoperation occurred within 120 days, especially during the spring-summer storm season and then find a cause for each misoperation can be overwhelming. For example, the April 27, 2011 storms took months of restoration before investigation of possible misoperations could begin. That particular storm caused about 20 misoperations. TVA would like to see the window of time extended to 180 days.
Response: Thank you for your comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.** **As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Southern Company	No	1. The question is missing a key component: Requirement R1 requires the responsible entities to identify and review each Protection System operation that operates the entity's interrupting device, designate each Misoperation, and investigate each misoperation and document the findings...The first two items are reasonable; however, the 120 days to 'and investigate each misoperation and document the findings...' can be problematic and creates a documentation requirement for something that is still under investigation. See Comment below

Organization	Yes or No	Question 2 Comment
		about timeframes. 2. The requirement says entities will “review each Protection System operation that operates the entity’s interrupting device...”. In R1, the requirement to “designate” is not defined. Is this a classification of each operation as a correct operation or a misoperation (as indicated by the VSL)? Or is this an annotation of each operation per Attachment 1? Or is this a declaration of which type of misoperation this is? Or other? Would a spreadsheet with each operation listed with an indication of correct or incorrect with a date noted be sufficient; or is other docuemtnation required? 3. What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain “...such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard.” A narrow reading of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. 4. In addition, under R1.1, the second requirement associated with notification of another entity should be stated as a separate subrequirement.

Response: Thank you for your comments.

1. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn’t reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R2) to continue the investigation.**

2. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**

Organization	Yes or No	Question 2 Comment
3. The revised Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard excludes any control operations even if those functions are embedded in a protection device. **4. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
ITC	No	Requirement R1 states that all operations need to be identified and reviewed. This requirement should clarified to exempt out-of-service equipment.
Response: Thank you for your comments. **Protection System operations which occur with the protected Element already out of service, that do not trip any in-service Elements, cannot be Misoperations.**		
Cleco Corporation	No	Please add some example(s) in the Guidelines and technical reference that outline what is meant for the review in R1. Does a review require a detailed report or could a simple check box be used for a review?
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. A review is an initial investigation to determine whether an operation is correct or a Misoperation. The drafting team is not being prescriptive as to what a review entails; both of your suggestions would suffice. It is left to the entity to determine what method is used to perform and document the review for the purpose of classifying an operation as normal operation or Misoperation.**		
Wisconsin Electric	No	1. In R1, the existing wording begins with: "Within 120 calendar days of an interrupting device operation ...". This wording does not specifically require a review in situations where an interrupting device fails to operate for a fault or abnormal condition. Perhaps the wording should be expanded to include these non-operations in the requirement as well.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
The drafting team believes that in the case where an interrupting device fails to operate for a fault or abnormal condition, in all but rare conditions a back-up protection will eventually operate an interrupting device triggering the start of an investigation. The drafting team believes these rare conditions would not affect BES reliability.		
Manitoba Hydro	No	The wording of this requirement is not clear enough for us to determine if we agree with it. Specifically, in R1.1 it is not clear how extensive the review of each Protection System operation should be. In reading the words of the Requirement versus the words in the associated Measures, the review process seems a lot less onerous in the wording of the requirements versus the wording of the measure. Perhaps adding additional wording to the requirement, listing the steps that should to be undertaken during the review, or even providing a review template would provide additional clarity and consistency. An entity cannot be found non-compliant with a measure, only a requirement, so the requirement should be clear when read on its own without the measure.
Response: Thank you for your comments **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team is not being prescriptive about what a review entails, it can be as detailed as the entity deems necessary to indicate it has examined the operation to determine whether it was a correct operation or a Misoperation.**		
American Electric Power	No	AEP believes that PRC-001, rather than PRC-004, is the most appropriate standard to address an entity being required to notify another entity of protection system disturbances involving Misoperations or otherwise. If the drafting insists adding such requirements to PRC-004, we recommend making the following changes to R1:a) For 1.1, striking the language "If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information" so that it simply reads " Identify and review each Protection System operation." b) Inserting an additional requirement inbetween 1.2 and 1.3 that simply states "If the investigating entity determines Protection System component(s) owned by another

NERC

Organization	Yes or No	Question 2 Comment
		entity contributed to the Misoperation, the investigating entity shall notify the owner of that Protection System component(s) and provide any pertinent information.”
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. This standard addresses correcting the causes of Protection System Misoperations and in recognition of the fact that many Protection Systems contain components shared between entities, it will be necessary for those entities to cooperate in order to execute a CAP to correct Misoperations.**		
ReliabilityFirst	No	ReliabilityFirst Abstains and offers the following comments for consideration: 1. Requirement R1 and subsequent requirementsa. ReliabilityFirst believes Requirement R1 and subsequent requirements rely on the operation of an interrupting device and the identification by its owner that a Protection System operated and whether it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard. First, the owner of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process. 2. Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it. 3. Requirement R1, Part 1.1a. ReliabilityFirst believes the second sentence in Part 1.1 is a separate thought and recommends removing it and creating a new Part 1.2. ReliabilityFirst recommends the following for consideration for the new Part 1.2: “Notify the owner of that Protection System component and provide any

Organization	Yes or No	Question 2 Comment
		requested investigative information if the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation.”
Response: Thank you for your comments. 1. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** 2. **The drafting team believes that in the case where an interrupting device fails to operate for a fault or abnormal condition, in all but rare conditions a back-up protection will eventually operate an interrupting device triggering the start of an investigation. The drafting team believes these rare conditions would not affect BES reliability.** 3. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP sees this requirement as specifying “how” to identify a Misoperation, not “what” comprises a Misoperation. Although, we understand that a robust process would include a prefunctory review of every relay operation, the need to capture and document each one in a manner satisfactory to an auditor adds no reliability benefit in our view. In fact, the vast majority of relay operations are NOT Misoperations and have a well-understood cause that is known immediately (e.g.; equipment fault). Based upon this thinking, PRC-004-3 R1 should only require an event be captured that is (a) known to be a Misoperation at the time of the relay action, or (b) the cause remains unknown an hour afterwards. This should greatly reduce the number of incidents that need to be recorded - and allows focus on those which do not have a simple resolution.
Response: Thank you for your comments. **The drafting team believes that all Protection System operations must be reviewed to ensure all Misoperations are identified. The drafting team is not being prescriptive about what a review entails, it can be as detailed as the entity deems necessary to indicate it has examined the operation to determine whether it was a correct operation or a Misoperation.**		
Dairyland Power Cooperative	No	Additional clarification should be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is

Organization	Yes or No	Question 2 Comment
		unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
Response: Thank you for your comments **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. An event continues through the last automatic reclosing shot initiated by the composite Protection System(s). Therefore, if a Protection System Misoperated multiple times during a system event, then it is only counted as one Misoperation. The drafting team believes that a single CAP or action plan can address multiple similar events in the event of a Misoperation however each operation must be reviewed to determine whether it was correct.**		
MISO	No	It is unclear on what "Designate each Misoperation" means. Designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Texas Reliability Entity	No	(1) It is not clear who is responsible for compliance with R1. Who must "identify and review", "designate" and "investigate"? Is it the owner of the interrupting device that operated, or is it the owner of a component that caused or contributed to the Misoperation? This will be difficult to enforce without clearly assigning responsibility.(2) The requirement and the VSL assume that there are two steps in identifying a Misoperation: "determining" that an operation is a Misoperation, and then "designating" the operation as a Misoperation. There is no requirement that an entity diligently and correctly "determine" that a Misoperation occurred during its review of an operation, and there is no VSL that applies when an entity incorrectly fails to "determine" that a Misoperation occurred.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.** **2. It is implicit in Requirement R1 that each entity must analyze each operation and exercise due diligence to determine whether a Misoperation has occurred. The drafting team revised Requirement R1, the new Requirement R1 now states: "…determine if it was a correct operation or a Misoperation."**		
PSEG	No	We have divided R1 into two requirements (R1 and R2) below to clarify what occurs when a Misoperation occurs on a Protection System component owned by one entity and that Misoperation causes another entity's interrupting device to operate. Under the new R1 below, the interrupting device owner must first determine, within 90 days, if a Misoperation occurred and whose Protection System component was responsible. If another entity is responsible, that entity is notified. Under R2, the entity whose Protection System component misoperated must do the completed a Misoperation analysis within 210 days of when the Misoperation was identified. See below: R1. Within 90 calendar days of an interrupting device operation in its Facility, each Transmission Owner, Generator Owner, and Distribution Provider shall determine if its Protection System (a) operated properly, or (b) had a Misoperation, or (c) operated properly with indications that Protection System component(s) owned by another entity had a Protection System malfunction that caused the interrupting device operation and, if applicable, shall complete part 1.1. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] o If condition (b) is the findings, the interrupting device owner shall be responsible for the investigation in Requirement R2.o If condition (c) is the findings, the other Protection System owner shall be responsible for the investigation in Requirement R2.1.1 For a condition (c) finding, the interrupting device owner shall notify the owner of that Protection System component(s) and provide any available investigative information that is requested by that owner in writing. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning.]o In the event that the owner of the interrupting device and the owner of the other

Organization	Yes or No	Question 2 Comment
		Protection System component(s) disagree on the interrupting device owner's determination in R1, the Regional Entity shall investigate and make a determination as to which entity is responsible for the investigation in Requirement R2, and the identification of a Misoperation will be considered completed when Regional Entity's decision is rendered.M1. For R1, each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence of the date of the interruption device operation and the date it completed its review of each interrupting device operation, including its associated determinations. Evidence for Part 1.1 includes documentation of written transmittals to the other Protection System owner (notifications and requested information) including, but not limited to, transmittal e-mails, log entries, or letters.R2. Within 210 calendar days after identifying a Misoperation per R1, the responsible Transmission Owner, Generator Owner, and Distribution Provider shall complete an investigation report of each Misoperation that state the Misoperation category and cause. If no cause is determined, the report shall state that. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]M2. Acceptable evidence for Requirement R2 may include, but is not limited to, a copy of a dated investigation report with documented findings for each Misoperation, including a description of the equipment involved in the Misoperation.
Response: Thank you for your comments. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team believes it would be cumbersome to create 2 requirements for this step and disagrees with the suggested timelines. Please see the rationale boxes and the Guidelines and Technical Basis section of the standard for the drafting team's thoughts on timelines.**		
Liberty Electric Power LLC	No	See comments in Q1.In addition, the standard needs to specifically exclude reverse power relay activations from misoperations analysis, as these activations are a normal event in the shutdown of many units.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **Section 4.2.4.1 specifically excludes non-protective relay functions (such as control functions associated with reverse power relays) that may be imbedded within a Protection System. In addition further guidance on this is provided in the Guidelines and Technical Basis section.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	1.The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. We are, not in favor of a zero defect approach, especially when most relay operations operate correctly. We recommend using approaches similar to what the COM-003 and CIP v5 teams are considering. 2.R1 does not work well with the definition of Misoperation. In other words, in order to “(d)esignate each Misoperation” as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection system operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3.In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was “slow” or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence?It would seem to us that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. **1. The drafting team revised the standard to include the approach you suggest above.** **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**		

Organization	Yes or No	Question 2 Comment
3. The phrase "slower than intended" in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.		
Independent Electricity System Operator	No	It is unclear on what "Designate each Misoperation" in R1.2 means. If could mean identitying that it was indeed a case of protection system misoperation, or designate a relay operation as a Misoperation or designate an identified Misoperation to a specific class or category. This part needs to be expanded.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Sacramento Municipal Utility District	No	We agree Misoperations should be identified and their causes corrected. However, it is an administrative burden requiring entities to keep lists of ALL operations to prove compliance that EVERY operation was reviewed. It is strongly encouraged to model compliance requirements after the Internal Controls model currently be implemented in other standard projects rather than creating requirements that subject an entity to be in violation for missing documentation of a single review.
Response: Thank you for your comment. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
City of Tallahassee	No	1.2 requires we 'Designate each Misoperation'. I disagree with this requirement as it is inherent with the investigation that a SME will designate without it being a requirement and the need to track it.
Response: Thank you for your comment. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		

Organization	Yes or No	Question 2 Comment
Requirement R1.2 is written specifically to ensure each Protection System operation is reviewed to identify a Misoperation. The point of the standard is to identify and correct Misoperations and this is the first necessary step to accomplish that goal.		
Indiana Municipal Power Agency	No	1. This standard is for identifying and correcting Protection System misoperations. By requiring the identifying and reviewing of all interurupting device operations caused by a Protection System operation and then having the enity be found non-compliant to a requirement within this standard for not doing these actions, the SDT has made this an interrupting device operation tracking standard along with identifying and correcting misoperations. IMPA does not agree with this approach. 2. IMPA does support the recommendation from Florida Municipal Power Agency in using the zero defect approach.In additoin, Indiana Municipal Power Agency agrees with the additional comments submitted by Florida Municipal Power Agency (FMPA)for this question.
Response: Thank you for your comments. **1. The drafting team believes the automatic operation of the interrupting device is the most logical way to start the process of having the owner of that device analyze the Protection System operation to ensure it was correct. There is no other way to detect each Misoperation other than to analyze every Protection System operation.** **2. Please see the drafting team's responses to FMPA's comments.**		
Tampa Electric Company	No	1. The standards takes a zero defect approach, especially in R1 which requires investigating every protection system operation; hence, if one protection system operation is missed, a violation occurs. TEC is not in favor of a zero defect approach especially when most relay operations operate correctly. TEC recommends using approaches similar to what the COM-003 and CIP v5 teams are considering. 2. R1 does not work well with the definition of Misoperation. In other words, in order to "(d)esignate each Misoperation" as required, the entity will need to have evidence that a fault actually existed. This can be quite difficult, especially for a protection

Organization	Yes or No	Question 2 Comment
		systyem operation with a successful reclose (e.g., due to lightning strike for instance), how is an entity to prove that the fault existed? 3. In addition, measuring clearing time can be quite problematic, especially for electromechanical relays. How is an entity to gather evidence that relay operation was “slow” or not, and hence identify a misoperation due to slow operation? Does this require installation of equipment to be able to gather sequence of events evidence?It would seem to TEC that a focus on internal controls for R1 is more appropriate to resolve some of these issues and challenges than the approach the SDT proposes.
Response: Thank you for your comments. 1. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.** 2. **The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.** 3. **The phrase “slower than intended” in parts 3 and 4 of the definition mean that the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.**		
Essential Power, LLC	No	In R1, the requirement to “designate” is not defined.The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor.

Organization	Yes or No	Question 2 Comment
		This form of protection is more "visible" during a normal stop event, but a reverse power relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitly stated that reverse power trips during a normal stop event be not considered as Misoperations.It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop (ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO’s standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to

Organization	Yes or No	Question 2 Comment
		function.
Response: Thank you for your comment. **Applicability section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.**		
Oncor Electric Delivery	No	1. The proposed R1 obligates the Transmission Owner or Generation Owner to now provide notification, coordinate communication and maintain documentation follow up with neighboring entities. It appears to misalign with the NERC Event Analysis program. 2. In addition, the Regional Entities have been tasked with designing a misoperations procedure for all Registered Entities in their respective area which appears to overlap this Requirement. Oncor recommends the appropriate NERC/Regional Entity subgroups revaluate to align NERC misoperations reporting which will ensure streamlined processes for Registered Entities.
Response: Thank you for your comments. **1. The NERC Event Analysis program and this standard do not overlap. The NERC Event Analysis program is in place to provide a coordinated response to a limited number of significant events as defined in Appendix E of the ERO Event Analysis Process document. If an event occurs that would fall into one of those categories then the entity would be expected to follow the ERO Event Analysis Process.** **2. PRC-003-1 will be retired with the approval of PRC-004-3; consequently, there will be no overlap after PRC-004-3 becomes effective.**		
Kansas City Power & Light	No	R1 requires detailed investigation of every protection system operation. If operational data indicates that only the intended breakers operated for a fault on a specific protected line and a fault record from any monitoring device in the area indicates the fault was cleared in the intended time then no detailed review of the

Organization	Yes or No	Question 2 Comment
		protection system operation is required.
Response: Thank you for your comment. **Every Protection System operation must be reviewed to determine whether or not a Misoperation occurred. The standard does not specify how the review is conducted but rather depends on the due diligence of the entity to analyze the Protection System operation thoroughly enough to determine if a Misoperation occurred.**		
CenterPoint Energy		1. A misoperation can result in the tripping of multiple interrupting devices that can be owned by more than one entity. Also, the various components of a Protection System, such as current transformers, dc control wiring, and dc supply, can be owned by different entities. Instead of the owner of the interrupting devices that operate, CenterPoint Energy believes the owner of the protective relays should have the sole responsibility for reviewing interrupting device operations and reporting any Protection System misoperations. This would provide more consistent reporting and eliminate any duplicative responsibilities and efforts. CenterPoint Energy recommends establishing the applicability to the owner of the protective relays. 2. With the responsibility of reporting misoperations on protective relays they own, including those that are categorized as 'Other than Fault', the owner of the relays must review interrupting device operations whether or not they own the interrupting devices. With such a performance-based requirement, CenterPoint Energy believes it is unnecessary to establish a requirement, such as R1.1, to "Identify and review each Protection System operation". CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: "Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified."
Response: Thank you for your comments. **1. The drafting team disagrees and believes the owner of the interrupting device is in the best position to initiate the**		

Organization	Yes or No	Question 2 Comment
investigation of the Protection System operation. **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. The drafting team believes every Protection System operation must be reviewed to determine whether or not a Misoperation occurred.**		
Associated Electric Cooperative Inc - JRO00088	Yes	Requirement R1.1.2 Replace: “Designate each Misoperation (if any)."With: “Designate each Misoperation (if any) in order to facilitate the reporting requirements in C-1.4 .”Rationale: Add clarityConcern: While AECI believes it understands the reason for R1.1.2's "Designation" existence, we question whether it can withstand the test of time and particularly hold-up to the proposed criteria within the "NERC Paragraph 81 Project".
Response: Thank you for your comments. **The reporting obligations of C 1.4 have been removed. The focus of the standard is to identify Misoperations and subsequently establish CAPs to correct them. Requirement R1 has been revised. Please review the new Requirement R1.**		
Tacoma Power	Yes	1. The general approach and intent is supported. However, how can an entity prove that it identified all BES Protection System operations? While processes should be in place to promptly identify all BES Protection System operations, it is feared that significant cost and resources will be required to “ensure” that all BES Protection System operations are identified, which could divert staff from key reliability activities. 2. A similar concern exists for identifying all Mis-operations. Recognizing that even the proposed, revised definition of a Mis-operation could be interpreted in different ways in some cases, it is conceivable that some entities could begin over-reporting possible Mis-operations out of an abundance of caution. It should also be recognized that not all Mis-operations are of equal impact to the reliability of the BES. Over-reporting by entities to avoid even the possibility of sanctions could pose a burden on Regional Entities and NERC and might distract

Organization	Yes or No	Question 2 Comment
		the industry from correcting the key Mis-operations impacting BES reliabity.
Response: Thank you for your comments. **1. The drafting team believes all Protection System operations must be reviewed to determine if a Misoperation occurred.** **2. The goal of this standard is not to qualify the severity of the Misoperation but rather ensure that the cause of every Misoperation is identified and corrected as stated in the Purpose.**		
Luminant	Yes	Luminant agrees with the approach but suggests the following improvements to R1 and sub-requirements. 1) R1 should address the interrupting device as a “BES” interrupting device. 2) Luminant recommends that the concept of ownership be continued from the main requirement to each sub-requirement. For example, in 1.1, it would be written as follows: “Identify and review each of its applicable Protection System operations.”
Response: Thank you for your comments. **1. The drafting team revised Requirement R1 to reference BES interrupting device.** **2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1.**		
Western Area Power Administration	Yes	While an entity can transmit information regarding a possible misoperation to another entity, the initiating entity cannot force a response. An entity which receives a transmittal is responsible for a response.
Response: Thank you for your comment. **The drafting team agrees with your observation. Requirement 1, Part 1.2 has been modified, Requirement 1, Part 1.2 now states that the receiving entity is required to investigate and document the findings for each Misoperation within the same 120 day period. Wording in M1 has been modified to read “Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information.” This would ensure the entity transmitting information to another entity about a potential Misoperation provided proper notification to the owner of the**		

Organization	Yes or No	Question 2 Comment
suspected component that contributed to the Misoperation.		
Utility System Efficiencies, Inc.	Yes	The standard should recognize the need for exceptions to the analysis of operations that are caused by unusual weather events. Large scale high wind events, extreme seismic events, hurricanes, tornadoes, ice storms, etc. can cause huge numbers of protection system operations of BES facilities. Many of these operations are momentary in nature and are caused by debris, out-of-right-of-way vegetation, and other line situations that are beyond established design limits for the lines and structures. Even the sustained outages may have been the result of a number of different causes, and a solid determination of the correctness of the operation may be impractical. The result of not having an exception for unusual conditions is that Transmission Owners would be spending protection personnel resources on non-productive documentation and processes, and not on maintaining and improving the reliability of the BES.
Response: Thank you for your comment. **As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Idaho Power Co.	Yes	Yes, it makes sense that the owners of the interrupting device and protection equipment should be the lead on the investigation.
Response: Thank you for your comment.		
Cogentrix Energy, LLC	Yes	The overwhelming majority of investigations by Generation Owners under the requirement in PRC-004-3 to review each Protection System operation (R1) will be for reverse power trips during normal stop events. It is understood that the Application Guidelines specifically states that reverse power relay operations be not considered

Organization	Yes or No	Question 2 Comment
		as Misoperations because the operation is a "control function" within the protective relay. But a reverse power relay is not a control device. It is a protective device. Its purpose is to protect the generator in the event the generator loses its prime mover and it begins to motor. This form of protection is more "visible" during a normal stop event, but a reverse power relay is providing this protection at all times. It is unclear as to whether the Application Guidelines is an enforcement "tool" and guidance provided in within may be used by the CEA to determine compliance by a Generation Owners. Since it is unknown, it should be explicitely stated that reverse power trips during a normal stop event be not considered as Misoperations.It is understood that the Application Guidelines stand separate from PRC-004-3 per se, but the former document will likely be used by auditors in determining whether or not investigations were thorough enough to identify Misoperations. We therefore expect it to be obligatory, if the standard is passed in its present form, to document the, “sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records,” for each normal stop (ref. the "Requirement R1" section of the Application Guidelines), including determining whether or not the Protection System operation was slower than expected ref. (items 2 and 3 in the "Guidelines and Technical Basis" section).The number of such events can be extremely large, since peaking units often stop and start daily (or even several times per day) in high-demand seasons. Retrieving such data would be extremely time-consuming; since, where DME exists (our RRO’s standard for PRC-002 has a minimum size threshold), GOs often do not have the centralized data collection facilities of TOs. Event analysis personnel may need to spend extreme amounts of time traveling to and from jobsites, since some peaking stations are unmanned or only minimally staffed. All this effort would result in no associated benefit regarding BES reliability. Reverse power relays are counted (perhaps inappropriately) as being part of the Protection System, but these devices do not trip in response to something having gone wrong. It is intended that negative current be experienced at some point as the unit unloads, and subsequent actuation of the reverse power relay is normal and expected. Notes should therefore be added to R1 and to the Application Guidelines, stating that tripping of the reverse power

Organization	Yes or No	Question 2 Comment
		relay during a normal stop event does not indicate a Fault, and a detailed investigation, DME downloading, speed-of-response analysis and the like are therefore required only if DME is present and if the reverse power relay failed to function.
Response: Thank you for your comments. **Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.**		
Ameren Services	Yes	(1) What influence do the Application Guidelines have on the CEA? For example, the Application Guidelines clearly and correctly explain "...such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." A narrow interpretation of R1 without this explanation could result in either frivolous violations or an entity expending considerable resources to document that every normal shutdown of a generator is a correct operation. (2) Clarify that the rationale is consistent with the Technical Basis page 17, by clearly stating that "the interrupting device owner is responsible to investigate operations initiated by a Protection System." (3) We suggest to augment the Rationale by adding at the end, "...and submit Attachment 1 data to the CEA per section C.1.4 Additional Compliance Information." A fair number of Misoperations trip another entity's interrupting device (e.g. DTT). R1 correctly requires the interrupting device owner to initiate the investigation, but once the Protection System component causing the Misoperation is identified, it becomes that Protection System owner's responsibility to report the Misoperation. We believe that under the present PRC-004-2a, there is confusion on this distinction. (4) We suugest to change R1 1.2 to "Designate each operation as correct or a

Organization	Yes or No	Question 2 Comment
		Misoperation. Group Misoperations for the same interrupting device that occur within 5 minutes for subsequent steps." IEEE 1366 (GUIDE FOR ELECTRIC POWER DISTRIBUTION RELIABILITY INDICES) defines 5 minutes as the demarcation between momentary and sustained events. Grouping multiple like kind operations into a single investigation / action plan / CAP is more efficient and avoids distorting statistics. It also improves BES availability and reliability by correctly reinforcing the appropriate use of automatic reclosing.
Response: Thank you for your comments. 1. **The Application Guidelines and Technical Basis section of the standard supplies the drafting team's reasoning and basis for writing the requirements. Consequently, the Guidelines and Technical Basis section provides background information for auditors and those responsible for implementing the standard. The Applicability Section 4.2.4.1 specifically excludes control operations such as reverse power relays. In addition further guidance on this is provided in the Guidelines and Technical Basis section. The standard includes all protective functions of reverse power relays and excludes any control operations even if those functions are embedded in a protection device.** 2. **The wording in the Rationale box has been revised.** 3. **The reporting obligations have been removed from the standard.** 4. **The drafting team revised Requirement R1. Please review the new Requirement R1. The drafting team believes that a single CAP or action plan can address multiple similar events. The scenario you describe is being reviewed by various groups to determine its impact on metrics.**		
Detroit Edison	Yes	
Santee Cooper	Yes	
Dominion	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Project 2010-05.1	Yes	
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
Nebraska Public Power District	Yes	
PacifiCorp	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 2 Comment
Exelon Corp.	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
NextEra Energy Inc.	Yes	

3. **Requirements R1, R2, and R3 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with these time limits? If not, please provide specific reasons why not and alternative recommendations.**

Summary Consideration:

Numerous commenters asked to clarify the time requirements under Requirement R1 when an entity cannot investigate due to extenuating circumstances and during extreme weather events. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.

As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

Several commenters asked the drafting team to combine all or parts of Requirements R1, R2 and R3 into one requirement with one timeframe. The drafting team believes an overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.

Some commenters noted that the focus of the standard should be on requirements that emphasize internal controls over an entity's process rather than actual work execution. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.

A few commenters requested the drafting team eliminate the "procurement of funds" wording in the Requirement R1 Rationale as capital budget cycles can expand through multiple calendar years. The drafting team agreed and revised the Requirement R2 Rationale to remove the "procurement of funds" reference.

A number of commenters suggested the quarterly reporting through the Regional Entities is sufficient for addressing the time requirements for handling Misoperations. The drafting team disagreed and responded with the following: "The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion."

Numerous commenters were confused about which entity was responsible for what actions when multiple owners were involved in an operation. The drafting team revised Requirement R1 to clarify that only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan.

Numerous commenters proposed various changes to the time requirements in Requirements R1, R2 and R3. The drafting team appreciates the suggested revisions to the standard but believes that the time requirements are appropriate. No changes were made to the draft standard.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	1. As with R1, Requirements R2 and R3 should be formatted to start with "Each...". For consistency with the preferred format of all NERC Standards, a Requirement should start with the responsible entities, followed by under under what conditions, and then what they have to do. 2. The time limits specified are excessive for plans that do not include correcting the problem. Correction of Misoperations is extremely important to reliability because the Misoperation may indicate a defect that could have significant consequences. The time limit for R1 should be 15 calendar days, an additional 15 calendar days for R2, and 15 days for R3. 3. A definite completion time period for correcting the Misoperation should also be specified. Sixty days would not be an excessive time assuming outages may be needed, hardware ordered, etc. to prevent a recurrence.

Response: Thank you for your comments.

1. **The drafting team believes made the suggested changes.**
2. **The drafting team believes the timeframes are reasonable considering the variety of possible system events, coordinating response crews and allocating resources, etc.**
3. **The timeframe for completing the CAP cannot be prescribed in a standard due to external factors such as outage restrictions, availability of parts, capital allocation and other circumstances that can cause a CAP to be delayed. The drafting team believes entities can reliably manage and assure CAP completions.**

Organization	Yes or No	Question 3 Comment
Souhwest Power Pool Reliability Standards Development Team	No	1. See above comment. 2. For those Major disturbances there needs to be a mechanism for extending the time frames without being penalized. 3. Additionally 60 days might not be enough time to procure funds for the CAP. 4. We are OK with the time requirement on R3.
Response: Thank you for your comments. **1. Please see the response to your comment on Question 2.** **2. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. This 120 day time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.** **3. The drafting team revised the Requirement R2 rationale based upon yours and other comments. The "procurement of funds" reference has been eliminated in the Requirement R2 rationale as it is not necessarily pertinent to the requirement.** **4. Thank you for the approval.**		
El Paso Electric	No	See EPE's comment in Question 2.
Response: Thank you for the comments. **Please see the response to EPE's comment in Question 2.**		
Santee Cooper	No	We agree with the need for NERC and the regions to review the timeliness of the

Organization	Yes or No	Question 3 Comment
		analysis of misoperations. However, the regional entities, based on the RAPA template for reporting misoperations and the quarterly reporting of these misoperations, already are getting dates from the entities for the date of the misoperation, the date the corrective action was completed or, if not complete, the expected completion date. Without any additional administrative manpower commitments, the regions can already assess through the spreadsheet how long each misoperation took to completion and question anywhere timeliness seems to be a factor. They can even assess the timeliness of the original analysis of the operation (and identification of any misoperations) by checking when a new misoperation is reported against the reporting period it should have occurred in. Therefore, it seems counterproductive to prescribe timelines per misoperation, that will mean that entities have new much larger administrative burdens put on their technical staff just to document that each analysis of each operation and misoperation meet the number of days allowed. There could still be a maximum limit of what is allowed time-wise without having all of the individual date requirements. For example, additional documentation could be tied to, say, if the corrective action is not complete after the 2nd quarter that the misoperation was submitted to the regional entity. This will allow the finer detail focus of both the individual companies and the regions to be the more complicated and longer timeframe misoperations, while still supplying data (but not more than is needed to find and correct the misoperation) about the other misoperations that occur.
Response: Thank you for the comments. **The drafting team disagrees. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion.**		
Dominion	No	1. R1 introduces a 120 day requirement in order for a correct and consistent review, and classification of, Misoperations. By introducing individual time requirements, this places unnecessary burden on entities to track dates associated with each phase of a Misoperation investigation and review. Dominion recommends an

Organization	Yes or No	Question 3 Comment
		approach similar to that recently taken in COM 003, through the development of a requirement to have a process and plan in place to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and adding additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and date recording. 2. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current language in the standard that includes 120 and 60 day requirements. Suggest using a 180 day overall time from the Misoperation date to finish one of these: 1)develop CAP, or 2)develop action plan or 3)develop declaration. Changes to the quarterly reporting template to remove and rename date fields will be needed and are included under question 5 comments. 3. Revisions should be made to the Misoperations reporting template to capture requirements not currently covered in the template. For example, R2 introduces the option of a “declaration”. The template should include a feature to record a declaration. Entities should not be required to use multiple tracking tools or techniques to document the various requirements. One tool should exist to do this and currently all entities use the reporting template. 4. All references to an investigation report should be changed to read “Misoperation investigation report” or “investigation report due to misoperations”. Without this change it could be interpreted that all operations require an investigation report. 5. R3 introduces an undefined term - an “action plan” for those misoperations without an identified cause. There is a concern that entities will be confused with Corrective Action Plan and action plan terminology. Suggest changing R3 to read “For each Misoperation without an identified, the Registered Entity cause(s), the Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the Misoperation, identify any additional investigative actions

Organization	Yes or No	Question 3 Comment
		and/or Protection System modifications., including a work timetable, or document why no further investigation or actions will be taken.

Response: Thank you for the comments.

1. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.**
2. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.**
3. **The NERC System Protection and Control Subcommittee (SPCS) is the group responsible for the Misoperations reporting template. The drafting team is forwarding all comments to the SPCS for consideration.**
4. **The drafting team agrees and added "Misoperation" to "investigation report" for clarity.**
5. **The term 'action plan' was utilized to allow for references within the standard for the activities that occur within Requirement R3 including references in Measures M3 and M4 as-well-as Requirement R4. While the term is not defined in the NERC Glossary, the drafting team believes there is sufficient clarity for use within the standard and modified the rationale box and the Guidelines and Technical Basis section of the standard.**

Organization	Yes or No	Question 3 Comment
Luminant	No	The time frames and activities in R1-R3 are confusing and can be simplified. Luminant suggests that R1, 2, 3 be revised to allow owners 180 days from the time of the BES interrupting device operation to investigate, determine the cause, and develop a CAP (cause known) or action plan (cause unknown). An action plan can result in identifying a cause and should include a CAP. If a cause cannot be determined, the investigation is closed. Below is our recommendation for R1-R3: R1. Within 180 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, the applicable Transmission Owner, Generator

Organization	Yes or No	Question 3 Comment
		Owner, and Distribution provider shall: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning]1.1 Identify and review each of its applicable Protection System operations. 1.2 For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System.1.3 Identify each of its Protection System misoperations, determine a cause (if known), and develop a Corrective Action Plan (CAP).R2. For misoperations where the cause cannot be determined within 180 days of the BES interrupting device operation, the applicable Transmission Owner, Generator Owner, and Distribution Provider shall develop an action plan to: [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning]o Develop a CAP within 60 days after identifying the cause of the misoperation for the Protection System component(s).o Where applicable, explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability and close the investigation.R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall implement its CAP according to the established timetable. [Violation Risk factor: Medium}{Time Horizon: Operations Assessment, Operations Planning].
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section has been revised to add clarity for the independent 120 and 60 day timeframes.**		
SERC Protection and Control Subcommittee (PCS)	No	1. SERC objects to the timetables and the compliance burden it places on entities: There is no evidence or indication that entities are not doing due diligence in reviewing operations. Quarterly reporting schedules help drives closure. 2. R1 correctly requires the interrupting device owner to initiate the investigation,

Organization	Yes or No	Question 3 Comment
		but when the Protection System interconnects with another entity and there are indications that the other entity's Protection System components misoperated (i.e. Other entity sends a spurious DTT), then, once the cause of the Misoperation is determined, it should be the responsibility of the owner of the Protection System that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. 3. R1 introduces a 120 day requirement for performing a correct and consistent review and classification of Misoperations. By introducing individual time requirements, this places an unnecessary burden on entities to track and document each phase of investigation and review of a Misoperation. Similar to the approach taken in COM 003 recently which included a requirement to have a process and plan to address Misoperations according to regional entity guidance and oversight. Many entities currently respond to misoperations in a timely manner and to add additional tracking and time requirements does not place the priority on addressing reliability, it places the focus on data collection and documentation. 4. In the event the SDT cannot accept Regional Entity oversight, then an overall time limit should be stipulated versus the current verbiage in the standard referencing the 120 and 60 day requirements. 5. All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report.

Response: Thank you for the comments.

1. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response,

Organization	Yes or No	Question 3 Comment
CAP creation and completion. The drafting team believes the timetables make the requirements measurable. 2. The drafting team revised Requirement R1 based on yours and others comments. Please review the new Requirement R1. 3. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard. 4. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. 5. The drafting team agrees and added "Misoperation" to "investigation report" for clarity.		
ACES Power Marketing Standards Collaborators	No	The SDT should consider providing an exception process if there are unforeseen delays that inhibit an investigation to occur within 120 days. For instance, there could be difficulties with coordination for multiple interrupting device owners. There are numerous reasons that could cause a delay to go beyond the 120 days, so there should be some sort of time allowance to provide extra time if the excuse is justified and reasonable.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	No	FMPA believes there ought to be exceptions for an “Act of Nature”, e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn’t reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Bonneville Power Administration	No	The time limits associated with R1, R2, and R3 are acceptable. Under the Compliance section, 1.4 requires a report to be submitted to the CEA within two calendar months following the end of each quarter. For an operation of an interrupting device at the end of a yearly quarter, the report will need to be submitted no more than 2 months after the operation. This will not allow the 120 days for review given by R1, nor the 60 days to develop the corrective action plan allowed by R2. BPA believes that the 2 month limit after the end of the yearly quarter to submit the report should be extended to agree with the 120 day limit of R1 and the 60 day limit of R2.
Response: Thank you for the comments. **The reporting obligations have been removed from the standard.**		
GTC	No	GTC does not agree to the timetables and the compliance burden it places on entities: While the intent is correct, to insure that all operations are being reviewed and misoperations are found and corrected, the quarterly reporting that we are

Organization	Yes or No	Question 3 Comment
		already doing is more than sufficient. Additionally, the NERC Standards Committee approved the draft SAR for Project 2013-02 "Paragraph 81" which identifies criteria for retiring or modifying existing Reliability Standards. The proposed time limits appear to conflict with the initial criteria identified via the P81 initiative. The dated limits would likely encourage entities to shift focus on closing out documents instead of spending the appropriate time studying the operation event to determine true root cause and development of an appropriate corrective action plan. Ultimately, the introduction of time limits would have little to no impact to the protection or reliable operation of the BES, and will likely find their way to the FFT process...and thus a future candidate for elimination via P81. GTC recommends the SDT to remove these introduced limits and refine focus to results-based to achieve the desired reliability result of analyzing operations to identify misoperations and implementing corrective actions to prevent future occurrences.
Response: Thank you for the comments. **The drafting team disagrees. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe the timelines are administrative or detract from the reliable operation of the BES; instead they add measurability to the goal of determining cause and developing appropriate corrective actions.**		
ISO/RTO Standards Review Committee	No	We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to provide reports within the allotted time frame. Priroritization should be given for events that are suspected to be misoperations based on the entities' judgment.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the**		

Organization	Yes or No	Question 3 Comment
investigation. **All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section of the standard, in the event of a natural disaster, 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 in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events.**		
JEA	No	1. If outages are necessary to properly examine and test protection system components 120 days may be too short especially during storm season. We recommend this be increased to 180 days. R1 also needs exceptions for major system events and natural disasters. 2. The R2 time frame of 60 days to develop a corrective Action Plan for the components of Protection misoperations is insufficient to consider applicability to other protection systems, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. Since the clock starts ticking as soon as the cause is identified, this should be extended to 180 days. Again it seems prudent to have an exception for major system events and natural disasters. If R1 & R2 timeframes were increased as suggested above this should result in an increase in this area also since the 180 day time frame was arrived at by adding the two preceding time frames. The new resulting time frame should be 360 days.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		

Organization	Yes or No	Question 3 Comment
2. All protection operations need to be reviewed. If a Misoperation is suspected, it must be investigated. Misoperations can be revealed at any time and are most likely to manifest themselves during system events. Therefore, it would not be prudent to simply ignore operations that occurred during large storms. As pointed out in the Guidelines and Technical Basis section of the standard, in the event of a natural disaster, 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 in relation to the timelines outlined in this standard. This guideline allows the entity to be afforded more time for unusual events. **3. The drafting team believes that 60 days is an appropriate timeframe for creation of a CAP including consideration of items mentioned in your comments. The completion of the CAP is determined by the timeframes identified by the entity in the CAP and should consider such things as available resources and outage schedules.**		
Operational Compliance	No	Distinguishing between NERC and WECC time requirements and deciding which is "more stringent" is too confusing and time-consuming. WECC requirements should fully complement and enhance NERC requirements. The WECC quarterly reporting system already in place is essentially a good one. In a nutshell: Q1. W/in 60 days of end of Q1 - elements of PRC-004-3.R1, Q2. W/in 60 days of end of Q2 - CAP created and documented, Q3. W/in 60 days of end of Q3 - CAP in place or reason for no CAP.
Response: Thank you for the comments. **The Project 2010-05.1 drafting team has no control over the WECC standards. Regional standards must be more stringent than the Continent-wide NERC standard. The drafting team included the following in the Background section of the draft standard: "Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard." The reporting obligations have been removed from PRC-004-3.**		
TVA Transmission Operations and Maintenance	No	The time limits do not allow for equipment that is difficult to get out of service to allow testing/troubleshooting to investigate and develop a CAP. Often transmission line of transformer bank outages can only be obtained during very limited time frames or must be scheduled months in advance. Only after the investigation is complete can the final CAP be confirmed, depending on what is found during

Organization	Yes or No	Question 3 Comment
		investigative outages. The 180 days in some cases may need to be at least 270 or more for some investigations.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Nebraska Public Power District	No	For R1 there is 120 days to identify, review, designate, correspond with associated etitites and investigate a misoperation to determine the cause. For R2 there is 60 days to develop a CAP once a cause is determined. This seems somewhat confusing in it may cut in to the 4 month time frame for R1. Perhaps it would be better to just state that a corrective action plan shall be developed within 6 months as in R3. This would be 6 months to create a CAP as the maximum interval or declare why a CAP is not needed. This may also be easier to audit since documenting when the cause is determined to start the time line would not be required. The VSL could then be updated and be simplified.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days.**		
PacifiCorp	No	PacifiCorp is concerned that the 120-day time limit in R1 is insufficient. When two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase to 90 days for each entity to complete their

Organization	Yes or No	Question 3 Comment
		respective activities in sequence. This would increase the total from 120 to 180 days under R1.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Southern Company	No	1. We do not agree with the introduction of the noted timeframes. There is no indication that the extremely large percentage of entities have not been doing due diligence in analyzing operations, identifying misopertions, and taking appropriate actions to prevent reoccurrence all of which are inherent to the existing Standard. If the only reason to place these time limits is to have a basis for compliance (i.e. you can't require someone to do something unless you tell him how long he has, because he can always say 'I was going to do it tomorrow); then, the time limits should be removed. We offer two potential suggestions for improvement: 2. R1 should not be changed from the previous posting. The requirement should be that the entity has a procedure and process. Compliance can be gauged based on an entities compliance culture, oversight and review of processes and procedures. The SDT should utilize the approached introduced in their recently posted- COM-3. or 3. It is suggested that all Protection System operations for a given quarter are reviewed, analyzed, classified before the reporting due date to the RE (at the end of two calendar months following the quarter) - this will cover all of the deadlines found in requirements R1, R2, and R3. Also, we believe that any required CAP

Organization	Yes or No	Question 3 Comment
		should be developed and documented by this same date. Placing the 120 day and 60 day time frames for each Prot Sys operation unnecessarily complicates the evaluation, resolution, tracking, and documentation of each misoperation. For a large entity with many operations per quarter, the multiple time frames for R1, R2, and R3 are unecessarily overbearing. 4. Requirement R3 should be combined with Requirement R2. A CAP developed and documented as described in R2 can address resolving identified causes of misoperations as well as addressing additional investigative plans for determining a cause. Misoperations with no identified cause can be handled as described in the draft standard.
Response: Thank you for the comments. **1. The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The drafting team believes the timetables add measurability to the goal of determining cause and developing appropriate corrective actions.** **2. The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.** **3. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days.** **4. Requirement R3 covers cases where there are significant challenges determining the Misoperation cause(s) such as outage constraints and multiple entity coordination. The 'action plan' developed in Requirement R3 establishes the course of action and the associated work timetable. While Requirement R3 (action plan) may appear similar to the Requirement R2 (CAP), its intent is different.**		
ITC	No	R1, 120 calendar days may not be enough time for those instances when multiple

Organization	Yes or No	Question 3 Comment
		outages occur during large storms such as hurricanes, tornadoes, etc. This needs to be addressed in R1 and should allow that an extension can be requested for those types of events reported in DOE 417 and EOP 004.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis Section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
seattle city light	No	Seattle City Light (SCL) does not agree with the time limits. SCL agrees that it is important for reliability that Misoperation CAPs be created and implemented within a reasonable time, but does not believe that the reliability benefit that might possibility accrue from meeting staged interim deadlines for analysis and for creating a CAP outweighs the administrative compliance burden created to document that each interim deadline has been met. SCL instead recommends that a single time limit be required for implementing an appropriate CAP following each Misoperation. Furthermore, SCL recommends a somewhat longer period, of either 240 or 365 days, to accommodate seasonal constraints. For SCL, elements associated with a Misoperation occurring in October at the beginning of the winter storm season might, in a heavy winter, not be available for operational analyses and testing until the following March or April, a length of time that could exceed 180 days. Such seasonal constraints are not unique to SCL, but also exist in summer for entities in the southern parts of North America.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.** **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Cleco Corporation	No	1. For those Major disturbances there needs to be a mechanism for extending the timeframes without being penalized. 2. Additionally 60 days might not be enough time to procure funds for the CAP. 3. We are ok with the time requirement on R3.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and**		

Organization	Yes or No	Question 3 Comment
Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard. **2. The drafting team revised the R2 Rationale and removed the "procurement of funds" reference in the Requirement R2.** **3. Thank you.**		
Manitoba Hydro	No	The time limit for R2 should be changed from "60 calendar days of identifying the cause" to "180 calendar days from the misoperation". Requiring the entity to track both the date of the operation (for R1) and the date the cause was identified (R2) seems like unnecessary work. This suggestion does not change the maximum time to complete R2.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.**		
NorthWestern Energy	No	We have a concern on R2 on the 60 calendar days to make a CAP (corrective action Plan). Making a plan with a timeline in 60 days poses an issue where budgeting is required to perform a major relay upgrade to fix a problem. We fear this wording could expose us to potential penalties for not meeting a CAP's stated time line that would be made before the budgeting approval and scheduling process is completed.
Response: Thank you for the comments. **The drafting team understands that the capital budgeting cycle for many entities can extend for many months however the drafting team believes there is sufficient latitude in the standard to revise a CAP and associated timeframes as needed by the**		

Organization	Yes or No	Question 3 Comment
entity. The entity can set the work timetable as identified in Requirement R2 and the Guidelines and Technical Basis section "Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented." Allowances for changes to a CAP are accounted for in the standard.		
American Electric Power	No	1. In general, AEP supports the idea of time limits in regards to R1, R2, and R3. However, though these proposed limits might be reasonable and attainable under normal operating conditions, the proposed time limits for R1 and R3 would not likely be reasonable during major distubances and significant events. The volume of analysis required in these situations is simply too great and complex to complete in the time limits proposed. Either the time limits proposed need to be extended to accommodate analysis during major distubances, or else there must be provisions for granting time extensions when major events occur. For example, if there was an event that was in scope under EOP-004 disturbance reporting, that entity could be afforded the flexibility to work out the allowed time limits with their Regional Entity. 2. In addition, an entity's allowed time window to repond should not begin until it has officially received notification.
Response: Thank you for the comments. **1. The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.** **2. The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to**		

Organization	Yes or No	Question 3 Comment
create a CAP or an action plan as stated in Requirements R2 and R3.		
ReliabilityFirst	No	ReliabilityFirst Abstains and offers the following comments for consideration:3. Requirement R2a. ReliabilityFirst believes the phrase "Within 60 calendar days of identifying the cause(s) of each Misoperation" relates to the designation of the cause of each Misoperation as identified in Requirement R1, Part 1.3 or as identified through implementation of the action plan per Requirement 4, Part 4.1? If so, ReliabilityFirst recommends add the parenthetical "(per Requirement R1, Part 1.3 or Requirement R4, Part 4.1)" to Requirement R2 in order to further clarify when the timing of the 60 calendar day window begins.
Response: Thank you for the comments. **The drafting team revised the rationale boxes for Requirements R2, R3, and R4 based on your suggestion.**		
Portland General Electric Company	No	1. Managing multiple deadlines based upon event date is difficult and does not align with quarterly reporting requirements (also see response to question 5). If more stringent deadlines are to be applied, there should be separate deadlines for identification of misoperations (less than 120 days) and identification of the cause (more than 120 days). Complex events affecting multiple workgroups or entities as well as those involving equipment failure may result in entities taking more than 120 days to determine the Root Cause. Often misoperations result in the need to send protective relays back to the manufacturer, but relay manufacturers have no requirement to meet these deadlines. Not allowing sufficient time to determine the Root Cause will result in more events being referred to R3 (no identified cause) or CAPs being developed based upon incorrect causes. 2. Complex events affecting multiple work groups or equipment failure may result in an entity taking more than 60 days to develop a CAP even after a cause is identified. Not allowing sufficient time could result in less than desirable CAPs.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comments. 1. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages or coordinating with outside entities. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.** 2. **The drafting team disagrees. The team believes that 60 days is adequate to develop and document a CAP once the cause has been identified. The completion of the CAP, including any revisions, is completely under the control of the entity.**		
LCRA Transmission Services Corporation	No	1. For the R2 time basis, the 60 day period for developing a CAP is reasonable; however, identifying the specific date the cause was identified could be subjective and could lead to an unnecessary violation due to a simple clerical error. We would recommend stating the CAP should be developed within 180 days of the interrupting device operation (the event). 2. We do not view R3 as being necessary and could even put an entity at conflict with R1 and R2 (i.e. the cause has not been determined within 120 days; however, the investigation continues and at day 140 the cause is determined and the entity is now in violation of R1) An entity should be able to complete all investigations within R1 requirements of 120 days, even if the finding is unknown. There is no benefit to extending the investigation out 180 days and beyond. Similarly, for an unknown cause a corrective action plan to plan and install controls to monitor the relay scheme to identify the cause of a repeat failure can be planned and executed within the requirements of R2 and R4.
Response: Thank you for the comments.		

Organization	Yes or No	Question 3 Comment
1. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes. **2. Requirement R1 does not require an entity to have a cause identified within 120 days. The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause such as multiple entity coordination, outage constraints, availability of parts and resource allocation. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required. Implementation of the action plan in Requirement 4, Part 4.1 will lead the entity to a cause or to a declaration that a cause cannot be determined on the entity's work timetable.**		
Dairyland Power Cooperative	No	R1 requires the identification and review of an operation, as well as the designation and investigation of a Misoperation, all within 120 days whereas R2 requires the development of a corrective action plan within 60 days of identifying the cause of a Misoperation. It is a concern that these proposed timeframes will create a disincentive for early identification of Misoperations. As an example, if a Misoperation is identified on day 2 after the incident, the corrective action plan must be developed no later than day 62 following the incident. However if an entity were to delay identification of the Misoperation until day 120 after the incident, the corrective action plan would not have to be developed until day 180. To prevent deterring entities from identifying Misoperations sooner, it suggested the drafting team consider requiring the corrective action plan by day 180 regardless of when the misoperation cause was officially identified. Doing so would avoid entities having to worry about the official date of Misoperation identification.
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of**		

Organization	Yes or No	Question 3 Comment
the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.		
MISO	No	Comments: We agree review of each Protection System operation is important, however, there could be voluminous events from a natural event that may be burdensome on entities to providereports within the allotted time frame. Priroritization should be given for events that are suspected to be misoperations based on the entities' judgment.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages and other factors. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Public Service Company of New Mexico	No	1. R1/R2: Regarding the proposed timeframes for completion of R1 and R2 as 120 days and 60 days respectively, PNMR suggests that the drafting team amend the requirements such that the combination of the two requirements not exceed 180 days, but allow for flexibility in either the analysis of the operation and/or the development of the CAP such that either one could be extended if needed but the entire timeframe allowed for both would not exceed the proposed timeframes as originally drafted.R1: PNMR proposes that an exception to the timeframe in R1 be allowed for complex failure to trip scenarios which are less frequent but can be difficult to recognize. PNMR requests that the time clock

Organization	Yes or No	Question 3 Comment
		start from the time of discovery rather than the time of the operation. The requirement would instead read: “R1. Within 120 calendar days of discovery of an interrupting device operation in its Facility caused by a Protection System operation,...” 2. Alternatively, PNMR suggests that there be an exception granted for certain failures to operate that are discovered after-the-fact.
Response: Thank you for the comments. **1. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an ‘action plan’ execution. If the cause is found via an ‘action plan’, the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.** **The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause such as multiple entity coordination, outage constraints, availability of parts and resource allocation. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required.** **2. The drafting team revised the standard to eliminate the need for exceptions. Please see the revised standard.**		
City of Austin dba Austin Energy	No	Given the length of the summer season in some parts of the country, Austin Energy requests an adjustment to the time limits to sufficiently account for outage constraints for investigative purposes. AE requests that R1 allow for 180 calendar days and R3 allow for 240 calendar days. (These comments are similar to those submitted by Seattle City Light which, due to the length of the winter season in their part of the world, they also requested a longer period).
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and**		

Organization	Yes or No	Question 3 Comment
investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Modesto Irrigation District	No	1. Standardize a single time frame for evaluation and remidiation. Keep it simple. 2. Also recommend longer time period for completion of remidiation, such as 240 days.
Response: Thank you for the comments. **1. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Technical Guidelines area has been revised to add clarity for the independent 120 and 60 day timeframes.** **2. The Corrective Action Plan (CAP) planned completion date is determined by the entity.**		
PSEG	No	In addition to the new R1 and R2 above, R3 through R4 below are an alternative to replace the proposed R1 through R3. R3. If the cause(s) for a Misoperation is identified in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 days of identifying a Misoperation per R1: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or o Explain in a declaration why

Organization	Yes or No	Question 3 Comment
		corrective actions are beyond the entity's control or would reduce BES reliability. M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.R4. If the cause for a Misoperation is undetermined in Requirement R2, the Transmission Owner, Generator Owner, and Distribution Provider shall, within 270 calendar days of identifying a Misoperation per R1, complete: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including an estimated timetable, or o A declaration explaining why no further actions will be taken. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R5 that must include a dated action plan or a dated declaration explaining why no further action will be taken.
Response: Thank you for the comments. **The drafting team appreciates your efforts and suggested revisions to the standard but declines to make the suggested changes.**		
Los Angeles Department of Water and Power	No	In regards to R2, the 60-day period for developing a CAP seems to be reasonable; however, this period starts from the date the cause of Misoperation is identified. "Date of cause" could be subjective and can potentially generate confusion and unnecessary violations. LADWP recommends using the date of "device interruption operation" and change "60 days" to "180 days."
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis**		

Organization	Yes or No	Question 3 Comment
section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services	No	We believe there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.** **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
Sacramento Municipal Utility District	No	We urge the Drafting Team to address the time limits and report requirements utilizing the Internal Controls Process thereby eliminating the 'zero-defect' language found in the requirements. While we agree with time limits to finalize any findings we disagree with the multiple date requirements. We believe that an internal control process should be identified by the entity that eliminates the potential for administrative errors. This would allow the entity to perform necessary actions and reporting in accordance to their policy specifically on facilities determined to be critical. Where an entity has a 'no-touch' in effect of certain facilities this method would allow them to evaluate the relays off the critical period.
Response: Thank you for the comments. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project. The drafting team believes the timeframes are sufficient and necessary and they will remain in the new standard.**		

Organization	Yes or No	Question 3 Comment
CenterPoint Energy	No	Instead of requiring a Corrective Action Plan be developed within 60 days of identifying the root cause, as provided for in R2, CenterPoint Energy recommends the timeframe be 180 days after the date of the misoperation. Requiring a Corrective Action Plan to be developed within 60 days of identifying a root cause would create a new, additional date that must be tracked. To facilitate the ease of tracking, as well as auditing, CenterPoint Energy recommends using the following for developing a Corrective Action Plan: "For each Misoperation with an identified cause, within 180 days after the date of the misoperation, the Transmission Owner, Generator Owner, or Distribution Provider shall:".
Response: Thank you for the comments. **An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the standard has been revised to add clarity for the independent 120 and 60 day timeframes.**		
Indiana Municipal Power Agency	No	Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency (FMPA).
Response: Thank you for the comments. **Please see the drafting team's response to FMPA.**		
Tampa Electric Company	No	TEC believes there ought to be exceptions for an "Act of Nature", e.g., event like a hurricane, that can result in a great many protection system operations but still require investigation of all of them within 4 months.
Response: Thank you for the comments.		

Organization	Yes or No	Question 3 Comment
The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation. **The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		
NextEra Energy Inc.	No	NextEra Energy Inc. (NextEra) disagrees that 120 days provides sufficient time to investigate all types of misoperations. For example, NextEra does not agree with the rationale that 120 days is sufficient time to account for outage constraints. This timeframe is particularly troubling in the context of nuclear power plants that generally do not schedule a switchyard outage unless it is consistent with its refueling outage - which can be as long as 18 months apart. Thus, NextEra recommends that R1.3 be revised as follows to provide a clearer process and more flexibility:1.3 Investigate each potential Misoperation and document the findings. The cause of a Misoperation may be initially listed as "Unknown/unexplainable" and the Analysis and Corrective Action Status listed as "Analysis - In Progress". The entity should continue their normal process of investigation and after a cause is determined resubmit the Misoperation to update the information.
Response: Thank you for the comments. **The drafting team believes that 120 days is adequate to review the operations to determine if they are Misoperations and investigate the Misoperations with consideration given to obtaining appropriate outages. If the investigation doesn't reveal a cause within this timeframe, then the entity is provided another 60 days to develop an action plan (per Requirement R3) to continue the investigation.**		
Ameren Services	No	1. We suggest that "cause(s)" be changed to "cause" in R2 to avoid time limit confusion, and be consistent with the use of "cause" throughout the rest of this

Organization	Yes or No	Question 3 Comment
		standard. 2. Although wording is clear that R2 be completed within 60 days of identifying the cause, some entities may incur violations by glibly adding the 120 days in R1 to the 60 days in R2. We suggest pointing out that the entity will have to intentionally record and track when they've identified the cause, and providing an example in the Application Guidelines for R2 on page 18 will provide better clarity. For example, if the entity identifies the cause on 3/31 for a 3/1 Misoperation, they must develop and document R2 CAP by 5/30 (not 8/29). 3. We agree with the SERC PCS that introducing time limits is unwarranted and burdensome. Regional Entities now get quarterly Misoperation and CAP status reports and have sufficient information to monitor progress. 4. At most, a one year time limit for CAP completion or explanation of CAP duration could be used. A small number of CAPs will extend beyond one year due to their scope or outage restrictions. SERC has used a two year limit then requiring a formal explanation, and very, very few have reached this time limit.
Response: Thank you for the comments. **1. The drafting team revised Requirement R2 based on your suggestion and modified the Guidelines and Technical Basis section of the standard associated with Requirements R1 and R2.** **2. The drafting team believes the wording is sufficiently clear.** **3. The drafting team disagrees. The drafting team believes the timelines add measurability to the goal of determining cause and developing appropriate corrective actions.** **4. The timeframe for completing the CAP cannot be prescribed in a standard due to external factors such as outage restrictions, availability of parts, capital allocation and other circumstances that can cause a CAP to be delayed. The drafting team believes that entities can reliably manage and assure CAP completions.**		
Kansas City Power & Light	No	1. R2 requires development of a CAP and evaluation of CAP applicability to other locations. I recommend development of a CAP in 60 days for the specific location

Organization	Yes or No	Question 3 Comment
		where the misoperation occurred. CAP applicability to other locations may require more time depending on what the CAP involves. CAP applicability to other locations should be allowed a longer time frame such as 12 months. 2. R3 requires development of an action plan for misoperations with an unknown cause. Depending on the type of protection equipment in place it may not be possible to always determine the cause of every misoperation. For example electromechanical relays only provide targets and event reports may not be available. R3 seems to require that EM relays be changed out to digital relays in order to monitor for the next misoperation. The standard should not require this and R3 should be deleted.
Response: Thank you for the comments. **1. Requirement R2 specifies a CAP "for the identified Protection System component(s)" and doesn't specify required timeframes for CAP completion which is determined by the entity. It only requires consideration of the Misoperation cause at other locations. It is responsibility of the entity to define when and where to apply a CAP (or not) at "the entity's Protection Systems at other locations." A CAP can be revised to reflect changes in scope and completion date.** **2. Requirement R3 (bullet 1) doesn't require Protection System modifications but rather the development of an action plan which *could* include Protection System modifications to aid further investigation. Requirement R3 (bullet 1) doesn't specify replacement of electromechanical relays with microprocessor-based devices. The standard includes Requirement R3 to address those instances where there are significant challenges to determining a Misoperation cause and propose other investigative actions. The action plan developed in Requirement R3 allows the entity to set the work timetable and revise that timetable as required.**		
Exelon Corp.		1. The Application Guidelines should be part of the Standard because they provide better clarification of the activities and timelines associated with R1, R2 and R3. 2. For R2: Replace "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" with "Explain in a declaration if no further corrective actions are required and your rationale." "beyond the entity's control" may be subjective. Suggest including the following statement based on

Organization	Yes or No	Question 3 Comment
		wording in the Application Guidelines concerning a no CAP declaration: "A condition identified during an investigation that is addressed by existing maintenance activities would be justification for taking no additional corrective action." 3. Exelon comments: Suggest revising the time limit verbiage as follows in order to provide more clarity:R1 Within 120 days of the event, review to determine whether the operation was correct. For any misoperation, identify and document the cause. R2a If after the initial 120 days a cause is determined for the misoperation, within 60 days - Develop a corrective action plan for the identified protection system componentOrExplain in a declaration if no further corrective actions are required and your rationale R2b If after the initial 120 days no cause was determined for the misoperation, within 60 days - Develop an action plan that identifies additional investigative actions to determine the causeOrExplain in a declaration why no further action will be taken R3 Within 60 days of determining a cause under requirement R2b - Develop a corrective action plan for the identified protection system componentOrExplain in a declaration if no further corrective actions are required and your rationale.
Response: Thank you for the comments. **1. The Guidelines and Technical Basis section will be filed as part of the approved standard.** **2. The drafting team has revised the Guidelines and Technical Basis section of the standard for Requirement R2 to include examples of what is meant by "beyond the entity's control".** **3. The drafting team appreciates your suggested revisions to the standard but declines to make the changes.**		
Pepco Holdings Inc & Affiliates	Yes	The timeframes for R1, R2 & R3 are acceptable, since Requirement R3 provides a reasonable alternative if the investigation cannot be completed within the allotted 120 days in R1 (due to outage constraints, severe weather, resources, etc.). However, the commentary in the Rationale for R2 is misleading and incorrect with regard to the statement that 60 days is reasonable for the procurement of funds for a

Organization	Yes or No	Question 3 Comment
		CAP. Capital dollars needed to fund larger CAP's (like other capital improvement projects) are budgeted for during a yearly budget cycle, usually in the fall of the preceding budget year. As such, unless the CAP was small and can be funded by an emergency blanket project it could take up to a year to get the necessary funding approved. We would suggest removing the procurement of funds from the R2 Rationale since it is not a pre-requisite for developing a CAP.
Response: Thank you for the comments. **The drafting team revised the Requirement R2 rationale based upon yours and other comments. The drafting team revised the R2 rationale and removed the "procurement of funds" reference in the Requirement R2.**		
Southwest Power Pool Regional Entity	Yes	With the proposed time limits, NERC may have to clarify how and when entities submit to the RE database misoperations that are still under investigation.
Response: Thank you for the comments. The reporting obligations have been removed from the standard.		
Utility System Efficiencies, Inc.	Yes	See previous comments for questions 1 and 2.
Response: Thank you for the comments. **Please see the responses to your comments on Questions 1 and 2.**		
Idaho Power Co.	Yes	Yes, they seem reasonable.
Response: Thank you.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration believes that 120 days is generally sufficient to determine the root cause of most Misoperations - or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The additional 60 days to develop a corrective action plan time frame is acceptable to us as well.

Organization	Yes or No	Question 3 Comment
Response: Thank you for the comment.		
Texas Reliability Entity	Yes	We generally agree with the deadlines, but we have questions about how they apply in a multi-party situation. If a Protection System Misoperation is determined and an entity ("Entity A") determines that the cause of the Misoperation is due to a component owned by another entity (Entity B"), how does the 120 day time period apply? What if Entity A does not start its review until 60 days after the operation and tells Entity B on the 90th day? Entity A has identified the cause (Entity B component) but what timeframe is Entity B under to determine the Misoperation cause for the component? What exactly is Entity A's mandatory obligation, and what is Entity B's mandatory obligation, and what are the applicable deadlines?
Response: Thank you for the comments. **The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3. The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
City of Tallahassee	Yes	In lieu of R3, I agree with this.
Response: Thank you.		
Western Small Entity Comment Group	Yes	

Organization	Yes or No	Question 3 Comment
Associated Electric Cooperative Inc - JRO00088	Yes	
Detroit Edison	Yes	
Tacoma Power	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Western Area Power Administration	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Wisconsin Electric	Yes	
Tri-State G&T	Yes	
Clark Public Utilities	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 3 Comment
Orange and Rockland Utilities	Yes	
The United Illuminating Company	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Consumers Energy	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	
City of Tallahassee	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	

4. **The team has modified the standard to address Misoperations when two or more entities own separate components in a Protection System. Do you agree that the standard adequately deals with this situation? If not, please provide specific reasons why not and alternative recommendations.**

Summary Consideration:

Numerous commenters were confused about which entity was responsible for what actions when multiple owners were involved in an operation. The drafting team revised Requirement R1 to clarify that only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan.

A few commenters were concerned about meeting the requirements when a major disturbance occurs, such as a storm. The drafting team believes this issue is covered by the NERC Sanction Guidelines as discussed in the Guidelines and Technical Basis section of the draft standard. No changes to the standard were made to specifically address this issue.

A few commenters were concerned about ensuring cooperation between entities. The drafting team believes this issue is adequately addressed in the Guidelines and Technical Basis section of the draft standard. No changes to the standard were made to specifically address this issue.

A few commenters felt having formal notification to another entity of an operation was unnecessary. The drafting team disagreed and clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners.

A few commenters were concerned with the definition of "suspects" in triggering notification. The drafting team revised Requirement R1 to eliminate "suspects". The trigger for notification is now if the interrupting device owner cannot determine that an operation is correct.

A few commenters wanted a time period for a notified entity to do its own investigation. The drafting team declined to make this change. The notified entity has the remainder of the 120 day period, and if needed can establish an action plan with its own time table for further investigation to determine whether their component operated correctly.

A few commenters were concerned with the burden of tracking notifications, especially involving "receipts" from other entities. The drafting team revised Measure M1 to eliminate "receipts".

Organization	Yes or No	Question 4 Comment

Organization	Yes or No	Question 4 Comment
Pepco Holdings Inc & Affiliates	No	The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the interruption of a BES facility and not the owner of the interrupting device. See extensive comments on this subject in our response to Question 2 (Requirement R1).
Response: Thank you for your comment. **Please see our response in Question #2.**		
Southwest Power Pool Reliability Standards Development Team	No	1) There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn't a time frame for the other entity to return the data requested and seems like this could cause an entity to not meet the time frames specified in the requirements. 2) Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely manner.
Response: Thank you for your comment. **1) The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Application and Guidelines section, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.** **2) The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such major disturbances, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.**		

Organization	Yes or No	Question 4 Comment
Tacoma Power	No	Remove the second sentence under R1.1. At minimum, consider moving this sentence to R1.3 or creating a new R1.4. As written, this sentence is included in a sub-requirement that, in the overall process, has not yet even required designation of any Mis-operations. Presumably, at least part of the reason that this sentence was included was to mitigate any concerns that Entity A will wait before notifying Entity B, such that Entity B has little time to investigate before the deadline. However, as written, R1.1 would still permit Entity A to notify Entity B within 120 calendar days of the interrupting device operation, which would leave Entity B no time to investigate before becoming non-compliant, since per R1 the clock for investigation starts when the interrupting device operated. The bottom line is that, if Entity A suspects that a component owned by Entity B contributed to a Mis-operation, it is in Entity A's interest to take action; it is recommended that there be no explicit regulaotory requirement for notification.
Response: Thank you for your comment. **The drafting team revised Requirement R1; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3. The drafting team believes notification is needed to formally involve other Protection System component owners in resolving a potential Misoperation.**		
El Paso Electric	No	See EPE's comment in Question 2.
Response: Thank you for your comment. **Please see our response in Question #2**		
Santee Cooper	No	Initially, the investigation/reporting burden should fall on the owner of the interrupting device. However, once it is determined which entity's equipment caused the misoperation, the burden of reporting should shift to that entity.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team agrees with your comment and revised Requirement R1 for clarity.**		
Dominion	No	a). Subpart 1.1 does not provide for a clear hand-off when another entity's Protection System component contributed to a Misoperation of the first party. Specifically, it appears that the first party will have to develop its CAP to include a component owned by another entity and for which it has no control. The Application Guideline speaks to the need for various component owners to cooperate in the investigation and contact the Regional Entity should there be a lack of cooperation. This guidance needs to be clarified in the Requirement as compliance is measured against the Requirement, not guidance. Suggest adding Subpart 1.2 to state: "If notified by an entity that a Protection System component contributed to that entity's Misoperation, than It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken." If adopted by the SDT, then renumber existing Subparts 1.2 and 1.3 to 1.3 and 1.4 respectively. b). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the location of the Misoperation is agreed to by the various Protection System owners, then it should be the responsibility of the owner of the Protection System that misoperated to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different owners and the Protection System failure was due to a Protection System failure by an entity that had no devices that were interrupted at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. The process (especially reporting process and resubmittals) is simplified when the owner of the Protection System that misoperated is responsible for: interfacing with others

Organization	Yes or No	Question 4 Comment
		to analyze, developing CAP, implementing CAP and reporting. c). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that had the Protection System Misoperation to initiate reports and communicate other entity actions.
Response: Thank you for your comment. **1) The drafting team has clarified Requirement R1. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, and developing a CAP or action plan. The drafting team believes the wording in the Guidelines and Technical Basis section of the standard is sufficient.** **2) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **3) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
Luminant	No	Luminant disagrees with the concept of "If an entity suspects ..." phrase. Luminant suggests that the data exchange between entities with "interpendent System protection Systems" be as follows: "...For its Protection System operations that are interdependent with the Protection Systems of another owner, the entity shall notify the owner of the interdependent Protection System." The owner of other components in the Protection System may request information in performing their investigation.
Response: Thank you for your comment. **The drafting team believes notifying every owner every time an operation occurred, especially when the interrupting device owner knows the operation is correct, would be burdensome. The drafting team does agree "suspects" is vague and has changed Requirement R1 to make the notification trigger clearer.**		
SERC Protection and Control	No	1. Please refer to comments in #2 above (SERC comments 2 and 3). Also, consider the following:a). R1 correctly requires the interrupting device owner to initiate the

Organization	Yes or No	Question 4 Comment
Subcommittee (PCS)		investigation, but when the Protection System interconnects with another entity and there are indications that the other entity's Protection System components misoperated (i.e. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, it should be the responsibility of the Protection System owner that misoperated to report; thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure resulted from an entity that had no devices that were interrupted or affected at the location where the Misoperation occurred. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
Response: Thank you for your comment. For your comments in Q2, Please see our response in Question #2. **a) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **b) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
ACES Power Marketing Standards Collaborators	No	(1) There is no justification in the Rationale for R1 or in the Application Guidelines to show statistics that this scenario would occur regularly. The supplemental documents do not explain why the SDT felt that adding this provision to the standard was necessary. This concept seems to be a rare instance without a basis for adding it as a requirement. Considering that this requirement is on a timeline for which compliance would be measured. (2) The requirement's wording is subjective in nature and would be very difficult to provide documentation for "suspecting" another entity's component contributed to the Misoperation. Also, R1.1 seems to

Organization	Yes or No	Question 4 Comment
		skip a step - first the entity identifies and reviews all operations but the next step should be to identify Misoperations. Once Misoperations are identified, then the investigation for the cause of the Misoperation would occur. The investigation step is when an entity would consider if another entity's components or equipment would have been the cause to the Misoperation. Therefore, we recommend striking the second sentence of 1.1.
Response: Thank you for your comment. **1) The drafting team is aware of multiple instances where the components of a Protection System are shared. The interface between TOs and GOs at a switchyard is a very common example. Requirement R1 was written to address these kinds of issues.** **2) The drafting team does agree "suspects" is vague and has changed Requirement R1 for clarity.**		
Bonneville Power Administration	No	1. BPA believes the standard does not provide enough clarity for dealing with the different ownership arrangements. 2. In addition, BPA prefers not to be required to notify other owners of misoperations in their protection systems, as each owner should be responsible for reviewing the operations on their own equipment.
Response: Thank you for your comment. **1. The drafting team agrees with your comments and revised Requirement R1 for clarity.** **2. Interrupting device owners will notify other entities only if they are unable to determine if an operation was correct. Each owner is responsible for determining if their equipment functioned correctly.**		
GTC	No	a). R1 correctly requires the interrupting device owner to initiate the investigation, but when the Protection System interconnects with another entity and there are indications that the other entity Protection System components misoperated (ie. Other entity sends a spurious DTT), then once the cause of the Misoperation is determined, then it should be the responsibility of the Protection System owner that

Organization	Yes or No	Question 4 Comment
		caused the misoperation to report thus removing the burden of reporting from the interrupted device owner. In some cases there may be several devices interrupted which are owned by different entities and the Protection System failure was due to a Protection System failure by an entity that had no equipment that was interrupted or affected at the location where the Misoperation originated. Under the present PRC-004-2a, there is confusion on this distinction. b). There is also a suggestion that multiple entities utilize a joint investigation report. Again, the burden of reporting should lie on the entity that owns the Protection System that caused the Misoperation and they should initiate reporting and communicating other entity actions to correct the problem.
Response: Thank you for your comment. For your comments in Question #2, please see our response in Question #2. **a) The drafting team agrees with your comment and has revised Requirement R1 for clarity.** **b) The drafting team agrees with your comment. Entities may work together to create a single investigation report. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting. The drafting team clarified this in the Guidelines and Technical Basis section of the standard.**		
JEA	No	R1.1 requires that if an entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation then we are to notify the owner of that Protection System component and provide any requested investigative information. We recommend to add language such as the notified entity must provide any requested information.
Response: Thank you for your comment. **The drafting team believes that such language is not necessary. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. Please see the Guidelines and Technical Basis section of the standard for Requirement R1. The drafting team believes the initial notification was necessary to ensure all Protection System component owners were aware that an operation took place and that**		

Organization	Yes or No	Question 4 Comment
these owners needed to investigate the operation of their components for correctness.		
Southwest Power Pool Regional Entity	No	If Owner A notifies Owner B that Owner B's component contributed to a misoperation, after being notified, Owner B should be responsible for performing misoperations analysis and reporting. The way the standard reads, there is no responbility for Owner B to investigate a component that didn't operate but did contribute to a misoperation.
Response: Thank you for your comment. **The drafting team has revised Requirement R1 to clarify the overall process. Each owner is responsible for determining if their equipment functioned correctly.**		
Nebraska Public Power District	No	I have concerns with the requirement R1.1 and M1 related "demonstrating transmittal and receipt of information" such as saving correspondence or communications (notifications) with other entities as part of the analysis and corrective actions with this standard. The misoperation is identified and fixed (or not fixed) by means necessary for the involved entities following the other requirements. This requirement will add time burden for tracking communications that takes away from the goal to fix the issue. It also confuses the issue on who is responsible if a "receipt" of notification cannot be obtained. This would increase the difficulty for auditing as well and adds a subjective nature to what is considered acceptable correspondence. I recommend this part of R1 be removed or the proof that a transmitted notification was received by another entity not be required since that is not under the control of the sending entity. Also, rather than tracking numerous emails and notifications the option for lack of response is to appeal to the RE for help as stated in the application guidelines. It may be wise to have a contact/process at the RE assigned to follow up on these types of requests especially if the associated entity is not registerd.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The requirement only specifies tracking the initial notification. Measure M1 was revised to remove "and receipt". This notification is required only in cases where the interrupting device owner cannot determine if an operation is correct. The drafting team believes the number of potentially incorrect operations would be small enough that it should not be a burden.		
PacifiCorp	No	See comment #3
Response: Thank you for your comment. Please see our response in Question #3		
Southern Company	No	o It is noted in the Rational box for R1 that the owner of the component that cause the misop will create the CAP, etc. As such it is not clear who will report the Misoperation. i.e. If Owner A has a breaker open for a fault outside the zone due to a carrier that failed to send a block signal. Is an entities only responsibility to communicate to the other owner that his equipment didn't operate correctly? If so how do they know he ever reported it and/or did anything to correct the problem. It seems that the misoperation should be reported by the entities whose interrupting device opened in error. o Please clarify the statement in the Rational Box for R1: "The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request.
Response: Thank you for your comment. The drafting team revised Requirement R1 and its rationale box to more clearly indicate who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
ITC	No	1. It is unclear between R1 and R4 who needs to report the misoperation. R4 should specify the owner of the component that initiated the misoperation as the reporter so that a single misoperation is not reported by multiple entities. 2. In 1.1 once notified, the other entity should be allowed additional time (possibly another 120 days?) to analyze the Protection System operation to determine the

Organization	Yes or No	Question 4 Comment
		component that malfunctioned. As written there is only a single timeframe beginning with the outage.The word ‘necessary’ should be included between ‘any’ and ‘requested’ in R1.1.
Response: Thank you for your comment. 1. **The drafting team revised Requirement R1 to more clearly indicate who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.** 2. **The drafting team revised Requirement R1 based; please review the new Requirement R1. The notified entity has the remainder of the 120 day period per Requirement R1 to determine the cause of the Misoperation; then has at least 60 days to create a CAP or an action plan as stated in Requirements R2 and R3.**		
Cleco Corporation	No	1) There is an issue with the timing and requesting data from these other entities that own part of the protection system. There isn’t a timeframe for the other entity to return the data requested and seems like this could cause an entity to not meet the timeframes specified in the requirements. 2) Also going back to the Major disturbance if multiple entities are hit then they will be busy taking care of their own operations and may not have time to coordinate the data request in a timely maner.
Response: Thank you for your comment. 1. **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		

Organization	Yes or No	Question 4 Comment
2. The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such major disturbances, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.		
Tri-State G&T	No	It is not clear how the owner of the interrupting device that operates can designate and investigate the Misoperation of a Protection System component owned another entitity, but that seems to be what Parts 1.2 and 1.3 require. One solution would be to divide Requirement R1 into two requirements as described below."R1. Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each Transmission Owner, Generator Owner, and Distribution Provider shall identify and review each Protection System operation. If the entity suspects a Misoperation of a Protection System component owned by another entity caused an unnecessary interrupting device operation, notify the owner of that Protection System component and provide any requested investigative information.""R2. The owner of any Protection System identified as misoperating in Requirement R1 shall: 2.1 Designate each Misoperation. 2.2 Investigate each Misoperation and document the findings including a cause for each Misoperation, if identified. 2.3 Provide its Corrective Action Plan (CAP) to the other entity and notify the other entity upon completion of the CAP if the Protection System that Misoperated caused that other entity's interrupting device to operate."
Response: Thank you for your comment. **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that**		

Organization	Yes or No	Question 4 Comment
misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
American Electric Power	No	Please see our response to Question 2 where we suggest changes to R1 regarding such situations.
Response: Thank you for your comment. **Please see our response in Question #2.**		
Portland General Electric Company	No	There is a requirement to notify another entity if their component is suspected of contributing to a misoperation, but there is no requirement to respond to such notifications. Accountability to report back to the entity providing the notification should be included to ensure that entity can maintain its own compliance. Events involving transfer trip on interconnections, for example, could involve misoperations of equipment owned by both entities and require significant cooperation during the investigation phase.
Response: Thank you for your comment. **It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. Please see the Guidelines and Technical Basis section of the standard for Requirement R1. The drafting team believes the initial notification was necessary to ensure all Protection System component owners were aware that an operation took place and that these owners needed to investigate the operation of their components for correctness. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
Ingleside Cogeneration LP	No	It is not clear to Ingleside Cogeneration LP how a situation is resolved where interconnected Protection System owners disagree with the causes or mitigation of a Misoperation. We can easily envision a scenario where we have been informed by a neighbor that one of our relays contributed to a Misoperation - which we do not find to be the case. This seems like it could result in an audit finding that we did not report a Misoperation based upon someone else's evaluation.There may be recourse

Organization	Yes or No	Question 4 Comment
		in existing escalation procedures to engage the Regional Entity and even NERC at some point to resolve a conflict of this nature. Whatever the solution, we firmly believe that this pathway to resolution must be made clear as part of this project. If left open, the most subtle interaction issues will result in finger pointing in all directions - an unproductive use of everyone's time. Furthermore, problems of this nature are likely to identify previously unknown failure mechanisms, which could help all industry stakeholders. The Regions may have access to technical specialists who are best positioned to assist with an evaluation of this level of complexity.
Response: Thank you for your comment. **As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. The drafting team believes that owners almost always work together to resolve these issues. If an entity cannot reach agreement, but believes a Misoperation has occurred, it may involve its Regional Entity for help resolving the Misoperation.**		
Texas Reliability Entity	No	(1) We voted "no" on this draft because it is unclear who is responsible for various actions in multi-owner situations. The requirements need to clearly state who is responsible for compliance with each step of the identification, investigation, correction and reporting process. (2) We suggest that the team consider a solution such as: (a) the owner of the interrupting device should be required to identify the Misoperation and the suspected component that caused it, and then (b) the owner of the suspected component should be required to take the further steps to investigate and correct the problem and to submit the required reports. (3) Additional language is needed to clarify that, for Misoperation investigation and reporting purposes, the entity that owns the component that misoperated is required to submit the reports. Also, any CAP's should include the review of coordination issues between entities involved in the Misoperation.
Response: Thank you for your comment. **The drafting team has revised Requirement R1 to clarify who is responsible for what actions. Only the owner of a Protection**		

Organization	Yes or No	Question 4 Comment
System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.		
PSEG	No	We believe that our alternative language in #2 and #3 above is clearer. In addition, a Misoperation analysis is required even when a cause cannot be determined. After that analysis is completed, an entity either develops a CAP or an action plan.
Response: Thank you for your comment. **Please see our response in Questions #2 & #3. The drafting team agrees that an analysis is required and the findings must be documented every time a Misoperation occurs, whether or not a cause is found.**		
Consumers Energy	No	R1.1 seems to be intending that the owner of the interrupting device perform the intial investigation. If a Misoperation is identified and the Protection System is owned by another entity, the wording of the standard is not clear about which entity should be responsible for the CAP, etc. The rationale paragraph covers this, but of course won't be included once the standard is finalized. Are both entities responsible for documenting the operation/Misoperation?
Response: Thank you for your comment. **The drafting team revised Requirement R1 to clarify who is responsible for what actions. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
CenterPoint Energy	No	(a) CenterPoint Energy recommends deleting the second sentence in R1.1 that states: "If the entity suspects a Protection System component(s) owned by another entity contributed to a Misoperation, notify the owner of that Protection System component and provide any requested investigative information." CenterPoint Energy believes it is unnecessary to have a requirement to force entities to coordinate on misoperation analysis and corrective action, as there are existing avenues that are available, if necessary.(b) The CenterPoint Energy comments in Question 2 are related to this question. Establishing the applicability to the owner of the protective relays would establish the entity responsible for misoperations

Organization	Yes or No	Question 4 Comment
		reporting. CenterPoint Energy recommends R1 maintain only the wording from R1.3, resulting in the following wording for R1: "Investigate each Misoperation (if any) and document the findings including a cause for each Misoperation, if identified."
Response: Thank you for your comments. a) **The drafting team believes it is necessary to require communication in the standard. It is possible the owner of the Protection system component that misoperated will not be in a position to know that a Misoperation has occurred. Since they must meet the requirements in this standard, requiring communication ensures they will know they need to investigate.** b) **See our response in Question #2. The drafting team agrees that the owner of the Protection System component that misoperated is responsible for the CAP or action plan and reporting. The drafting team has revised Requirement R1 for clarity.**		
Detroit Edison	Yes	Yes - SDT did an excellent job with joint ownership issues.
Response: Thank you.		
Western Area Power Administration	Yes	An entity cannot be held responsible for another entity's failure to respond or act upon notice of a suspected misoperation.
Response: Thank you for your comment. **The drafting team revised Requirement R1 and Measure M1. Only the owner of a Protection System component that misoperated is responsible for documenting the findings, developing a CAP or action plan and reporting.**		
Exelon Corp.	Yes	o The standard needs to make it clear that an entity needs to provide information to another entity within a specified time period, e.g., a TO needs to provide information to a GO on a transmission line trip, within limitations of the FERC Standards of Conduct.
Response: Thank you for your comment. **Requirement R1 mandates all investigative work, including the passing of investigative information, be performed within 120 days**		

Organization	Yes or No	Question 4 Comment
of the interrupting device operation.		
Ameren Services	Yes	Yes, as long as the R1 rationale is augmented to clarify reporting responsibility as we recommend in items 2 and 3 of question 2 above.
Response: Thank you for your comment. **Please see our responses in Questions 2.**		
Northeast Power Coordinating Council	Yes	
Western Small Entity Comment Group	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	

Organization	Yes or No	Question 4 Comment
Okanogan PUD	Yes	
National Grid	Yes	
seattle city light	Yes	
Wisconsin Electric	Yes	
Manitoba Hydro	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
LCRA Transmission Services Corporation	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 4 Comment
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Los Angeles Department of Water and Power	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
NextEra Energy Inc.	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
New York Power Authority	Yes, Yes	

Organization	Yes or No	Question 4 Comment
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)

5. **Attachment 1 lists and describes the data to be included in the quarterly reporting. Do you believe this data is appropriate for metric analysis? If not, please provide specific suggestions for improvement.**

Summary Consideration:

After consultation with NERC Legal staff and NERC's ERO Reliability Assessment and Performance Analysis group, the drafting team is removing the reporting obligations from the draft standard. The language in Compliance Section C 1.4 - Additional Compliance Information of the draft standard referencing reporting and Attachment 1 has been deleted. Also, because Attachment 1 was a reference document associated with the Quarterly Misoperation Reporting Form, it will not be posted with the draft standard. The removal of the reporting obligation from the draft standard does not result in a reduction of reliability. Compliance Section C 1.2 - Evidence Retention portion of the draft standard requires entities to retain evidence of compliance for audit and compliance purposes. Reporting is enforceable under NERC's Rules of Procedure, and NERC is currently in the process of preparing a data request under Section 1600 of the NERC Rules of Procedure. NERC would analyze the data collected pursuant to the data request, if approved, to develop meaningful metrics, identify trends in Protection System performance that negatively impact reliability, to identify remediation techniques, and publicize lessons learned for the industry. The data submitted as part of the proposed Section 1600 data request would not be used for compliance or enforcement purposes.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	An additional field should be added to improve the metric analysis of microprocessor relay malfunctions. For example, the field value for a microprocessor relay malfunction could include the following:Setting Error-Incorrect Numerical Input SpecifiedSetting Error-Incorrect User-Programmed Custom LogicIncorrect Design-Incorrect User ApplicationIncorrect Design-WiringFirmware Version Mismatch by UserOthers
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Tacoma Power	No	1) Why does an entity need to provide the Date Reported? It seems like the Regional Entity could provide this information based upon when they receive it. The person assembling the reporting data may not be the one actually submitting

Organization	Yes or No	Question 5 Comment
		it to the Regional Entity, and the submittal date may not coincide with dated that the reporting data is assembled. Therefore, two individuals may need to be involved. While not a lot of extra work, it is an additional administrative step in the process that seems to provide little value to reliability. 2) Additional information, or at least a reference to additional information, should be provided to describe TADS and GADS reportable events. 3) It seems like the following fields could be consolidated into one: Event Description/Analysis and Protection Systems/Components that Misoperated. 4) What penalties would be likely if an entity, acting in good faith, provides information that is later determined to be incorrect and is then updated in another reporting period? 5) Do all Mis-operations need to be submmitted with Submittal Type entered as 'Remove' before they no longer need to be resubmitted? Or, does the final submittal only need to have one of the following in the Resolution Status field, even if the Submittal Type is 'New' or 'Update':'Corrective Action Plan - Completed,' 'Action Plan - Completed,' or 'Declaration - Completed.'If a declaration is made, or an action plan is completed, and reported (submitted), does the associated Mis-operation need to be continually re-submitted while the status is 'Declaration - Completed' or 'Action Plan - Completed'? It seems like these two statuses are still somewhat open-ended. 6) Remove double slash in "Corrective Action Plan//Declaration Development Date."
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
El Paso Electric	No	EPE believes the columns in Attachment 1 requesting Event Analysis Completion Date; Corrective Action Plan/Declaration Development Date; or Action Plan/Declaration Development Date does not contribute to improving protection system performance.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Santee Cooper	No	The Incorrect Setting/Logic/Design Errors category needs to be split into separate categories to improve the data analysis. As relays get more complex, more of the protection system is becoming internal to the relay, and so this has become a disproportionately large category.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Dominion	No	a). Eliminate the field "Additional BES Interruptions". This places unnecessary burden on entities to report interruptions that may not be associated with a Power System Misoperation. There is no need to track or collect this additional input. b). Instruction for Attachment 1 needs to include specific information as to when to fill out specific data in this field. The template currently requires a brief description in the Event Description field and details in the Corrective Action field when classified as Corrective Action in Progress. Once the Corrective Action Plan is completed, the instructions say to clear this field (which we disagree with) and input cause information under the Event Description field. Recommend renaming this field from Event Description/Analysi to Event Description.c). d). There should be a means to separate Generation and Transmission. This approach doesn't appear to give entities the option of separating reports. e). Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. Provide examples how to separate settings from logic when it's all part of a smart relay setting. f). Please split Communication Failure into two separate categories, one for 'Power

Organization	Yes or No	Question 5 Comment
		Line Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. g). Please eliminate the TADS and GADS information. TADS only counts lines and transformers that operate, not any other equipment. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. However the definition of an operation and rules for determining the number of operations will need some clarity. h). Drop the word "general" in the field name Misoperation General Cause". No need to introduce another undefined descriptive word. i). Remove the following fields: "Event Analysis Completion Date", "Corrective Action Plan/Declaration Development Date", and "Action Plan/Declaration Development Date". j). Revise "Target Resolution Completion Date" to "Resolution Target Date". k). Revise "Actual Resolution Completion Date" to "Resolution Completion Date". l). Prevent entry of data into a field that was made not applicable by a previous field selection.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Luminant	No	1) The data provided by the quarterly report would have little, if any, reliability benefit to the BES due to the limited technical information provided in the Attachment. 2) Luminant recommends that a report be provided on an annual basis.
Response: Thank you for your comments.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
SERC Protection and Control Subcommittee (PCS)	No	1) Please change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. 4) Please eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. The SERC PCS recommends that the rules for determining an "operation" be consistent between TADS and PRC-004 reporting. Also need to coalesce data systems (GADS, TADS , PRC-004, etc.)
Response: Thank you for your comments. Please read the Summary Consideration for Question 5.		
Colorado Springs Utilities	No	Attachment 1 does not describe data that is appropriate for metric analysis for a couple reasons: (1) This standard applies to both Generation Owners (GOs) and Transmission Owners (TOs); however, GOs are not in a position to respond to the last item on page 1, "Additional BES Interruptions." GOs are responsible for BES equipment in their plants and are not responsible for BES equipment belonging to TOs. Therefore, GOs should not be responsible for determining any BES interruptions outside of the plants. We recommend removing the section, "Additional BES Interruptions". (2) If TADS/GADS data is required for metric analysis, then an explanation should be

Organization	Yes or No	Question 5 Comment
		provided for why the data is required. We recommend that NERC or the Regional Entity provide an explanation for the relevance of the TADS/GADS data to the metric analysis.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
PPL Corporation NERC Registered Affiliates	No	a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid. b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Bonneville Power Administration	No	BPA believes the data needed for metric analysis depends on what NERC hopes to learn from the data.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
GTC	No	1) Please change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. 2) Please split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. 3) Please split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance.
Response: Thank you for your comments. Please read the Summary Consideration for Question 5.		
ISO/RTO Standards Review Committee	No	It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
Response: Thank you for your comment. Please read the Summary Consideration for Question 5.		
JEA	No	1) Attachment 1 Field Name: Misoperational General Cause Field Value: Incorrect settings/Logical Design Errors are not a misoperation since the protection system operated exactly as it was programmed. Improper setting should be handled in PRC-005 (maintenance and testing). If we are going to include things that cause a protection system to not protect then there is little justification for not considering other equally as destructive problems such as the breaker opening slowly. It is inconsistent to send the message that human error is a problem but

Organization	Yes or No	Question 5 Comment
		mechanical error is not. Also by excluding human error they could better correlate with TADS, since TADS excludes human error for relay settings. 2) Section 1.4 clearly shows this is a requirement and so if it is required then make it a requirement and if it is not required then delete it.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Nebraska Public Power District	No	1) Need clarification on these items:For Registered Entity ID#: What is the option to fill in the field if the portion of the protection system that misoperated is owned by a non registered entity? 2) The fields Event Analysis Completion Date, Corrective Action Plan/Declaration Development Date, Action Plan/Declaration Development Date seem like they would not have much metric value and add extraneous information. These should be removed. 3) For the Reported By, Phone Number, and E-mail Address line items is this the compliance contact # for a utility or a specific person writing the report? Using specific names, email, and phone numbers can create issues either way. Perhaps it would be best to use more general contact information for the entities or a single point of contact so these line items would stay more constant.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Southern Company	No	1) This list is not inclusive of the present RAPA form. The SDT should insure that the RAPA form is modified to only include the data specified in the Standard. 2) o The TADS information should be removed since there are plans to start reporting # of operations thereby allowing appropriate metric analysis o 3) However, we have a number of recommendations intended to improve the structure and clarity of the standard and Attachment 1: a) The requirement

Organization	Yes or No	Question 5 Comment
		for reporting should be in the Requirements and Measures section as a requirement rather than in the Compliance section C1.4.â€, Attachment 1 needs to be part of the standard since it is referenced in the standard. 4) b) The Registered Entity ID # is not needed as the data submission occurs via web based portals and the RE knows who is submitting the data based on the log in credentials of the submitter. This information is superfluous. 5) c) The "Event Analysis Completion Date" and "Corrective Action Plan/Declaration Development Date" fields are not required if the combined R1 & R2 suggestion is implemented along with the deadline for these requirements being the report date to the RE. 6) d) There are too many classification choices in the "Resolution Status" field. One of three choices should be adequate to tell the RE what stage of evaluation/resolution is active: 1) Analysis - In Progress, which means [Still Under Investigation]; 2) Analysis - Completed - Corrective Action Plan Pending; 3) Corrective Action - Completed, which means [Investigation Complete, Corrective Action Complete] 7) e) Both the "Target Resolution Completion Date" and the "Actual Resolution Completion Date" fields are not needed. We suggest using only the "Target" date field and have the RE look at the Resolution Status field to determine if the Action Plan is Completed. We believe that all of these reporting dates are not necessary. 8) f) The "Date Reported" field is not needed - the submission due dates are fixed by the RE (and have been repeated on page 21 of the Clean draft standard dated 6 Jul 2012. 9) g) We believe that a linkage to GADS reporting is not necessary. In the many years we have been processing relay operations, we have had no reason to review any GADS information. The mis-opeation reporting and resolutino can be processed without the addition of non-useful information.
Response: Thank you for your comments.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
ITC	No	If an entity is required to report a misoperation due to a malfunction of another entity's component, then there should be a space for the other Registered Entity's name.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
seattle city light	No	1) I) There are too many classification choices in the "Resolution Status" field of the report form. An equally effective status report can be delivered using three choices: 1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) II) The form for GOs should differ from that for TOs, for the following reasons: a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid. 3) b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Cleco Corporation	No	Our issue is not with the requested data but how the data is submitted. The current spreadsheet is very cubersome and needs to be reformatted.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Wisconsin Electric	No	Under Equipment Type: Add an equipment Type, such as "Generator Tie Line", to indicate the conductors from the generator step-up transformer high-voltage terminals to the substation/switchyard bus. These conductors are not considered transmission Lines, so the "Line" equipment type designation would not be appropriate for these.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Portland General Electric Company	No	1) The fields listed in Attachment 1 are sufficient. However, the quarterly reporting requirement is buried under the Compliance Monitoring Process, but should be a clear separate requirement for the registered entities under the standard. 2) The reporting requirement R2 of UVLS standard PRC-022 is slated to be retired per Project 2013-02, but 4.2.2 specifically excludes UVLS from this standard. This could result in UVLS misoperations not being reported.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
New York Power Authority	No	Need to explain the relevance of the TADS and GADS data to the calculation of the

Organization	Yes or No	Question 5 Comment
		metric.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Exelon Corp.	No	1) o The list is good for a 50,000 foot level view of analysis results. Protection Systems are too complex and dissimilar to obtain meaningful analyses at the level of the Attachment. Also, understand that the purpose of Attachment 1 is not to trouble-shoot misoperation, only to provide a database of types of misoperations as a performance indicator. 2) o Item C1.4 - Additional Compliance Information requires the quarterly Misoperation Data - Attachment 1 to be submitted within two calendar months following the end of each calendar quarter. This does not allow for the time limits specified in requirements R1, R2, and R3 for investigating, identifying and creating a CAP for the associated misoperation.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
MISO	No	It is unclear whether or not Attachment 1 is part of the standard that must be complied with. The SDT should clarify whether the misoperation information listed in Attachment 1 must be provided as specified. If that is the expectation, then the data requirements must be stipulated as a Requirement. As an Attachment without associated Requirements, we interpret that data submission as not mandatory.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Texas Reliability Entity	No	(1) Is Attachment 1 considered to be part of the Standard? If so, then future modifications to Attachment 1 would have to go through through the SDT process

Organization	Yes or No	Question 5 Comment
		and would entail extensive time and effort to make. (2) Under current practice, in many cases there is insufficient detail provided by the entities involved in a Misoperation to understand the root cause. There has been some discussion with the Protection System Misoperation Task Force (PSMTF) that additional data would be helpful in categorizing misoperations. In particular, it would be helpful to add subcategories below the misoperation general cause codes (i.e. Incorrect settings/logic design could have subcategories such as modeling errors, calculation errors, etc.). (3) The Periodic Data Submittal requirements and the template should be flexible enough to permit Regional Entities to collect additional information which may be beyond the scope of the PRC-004 Standard, if deemed necessary based on regional needs. For example, in ERCOT, the current regional rules for misoperation reporting also include failure to reclose, reporting the generator trips < 100kV, sudden pressure relay misoperations, SPS misoperations based on a regional definition, etc. These are included in the current template to streamline the reporting process for the Registered Entities, rather than requiring multiple reports. Since this information is outside the PRC-004 applicability, it is removed from the quarterly Misoperation reports by Texas RE before data is submitted to NERC. The previous draft of PRC-004-3 had flexibility in the periodic data submission language to allow this ("using the format specified by the ERO"), but that language was removed in the current draft.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
The United Illuminating Company	No	UI does not agree with including any of the reporting process in the PRC-004 standard or its attachments. The information to report does not require Ballot Body Approval initially or each time a field is to be modified.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
Modesto Irrigation District	No	Resolution Status has too many options. Keep it simple. Suggest 1) Evaluation underway, 2) Evaluation Completed, Remediation activity begun, 3) Remediation activity complete.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Liberty Electric Power LLC	No	Limit resolution status to "work in progress" and "complete".Forms are too complex, with many elements not used by generator operators (example:TADS), or not known by GOPs ("Other BED elements", etc.)
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Cogentrix Energy, LLC	No	1) There are too many classification choices in the “Resolution Status” field of the report form. An equally effective status report can be delivered using three choices:1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) The form for GOs should differ from that for TOs, for the following reasons:a. GOs are not in a position to respond to the last item on p.1, “Additional BES Interruptions.” We know only what happens in our plants, not repercussions on the grid. 3) b. The “slow trip” entries in the “Misoperations Category” do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if

Organization	Yes or No	Question 5 Comment
		the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. 4) Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). 5) Additionally, there is no reference to reporting in a manner outlined by the CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Independent Electricity System Operator	No	We have a difficulty determining whether or not Attachment 1 is part of the standard and therefore must be complied with. As presented, Attachment 1 is referenced under Section C 1.4, Additional Compliance Information. Section C specifies the compliance monitoring/audit evidence requirements and which are not regarded as a standard Requirement that must be complied with to achieve a reliability outcome. Further, as with the list of evidence presented in CANs and RSAWs, the information/record presented in these documents are examples of acceptable evidence. Deviations from the specified information are acceptable for so long as the information provided can demonstrate compliance with the Requirements. If the SDT holds the position that the misoperation information listed in Attachment 1 must be provided as specified, then the data requirements must be stipulated in a Requirement. Having data requirement not stipulated in a Requirement will render that data submission not mandatory.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Sacramento Municipal Utility District	No	We feel the data is appropriate. 1) However, we feel the trending data is more appropriately collected thru NERC's Section 1600 process. As no clear information is provided how the data is to be utilized we don't believe it should identified nor included as a compliance component. Further, national trending may inappropriate skew information that may be region specific diluting the results. 2) Also, including the attachment in the standard would require a drafting team for any changes for requested data.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
CenterPoint Energy	No	(a) CenterPoint Energy is concerned that the 'Slow Trip - During Fault' misoperation example that is used in Attachment 1 may be misleading and could result in incorrect reporting; therefore, we recommend developing another example, such as, an 'Unnecessary Trip - During Fault' misoperation which is a more commonplace. Although there may not enough information included for the proposed example to know for certain, CenterPoint Energy suspects that there may have been a non-communications-based, directional time-overcurrent relay, which was part of the Protection System, which ultimately tripped the transmission line. Such a scenario may not be a reportable misoperation, as the proposed Misoperation definition for 'Slow Trip - During Fault' includes the following clarification: "Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems." In other words, the following is stated in the Guidelines and Technical Basis: "Delayed

Organization	Yes or No	Question 5 Comment
		fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems." (b) The 'Equipment Voltage (kV)' field in Attachment A states: "Enter the system voltage of the BES equipment associated with the Protection System that Misoperated. For transformers, use the high side voltage." While using the high side voltage could be appropriate for generator step-up transformers, CenterPoint Energy recommends the system voltage for autotransformers be based on the low side voltage, in order to provide consistency with other NERC criteria, including Reliability Standards, such as, PRC-023 Transmission Relay Loadability.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Ameren Services	No	We suggest to (1) change 'Time Zone' Field Value to prevailing time (e.g. CPT for Central Prevailing Time) to make reporting more efficient. (2) split Incorrect Setting/Logic/Design Errors into three separate categories to improve the usefulness of the metrics regarding Protection System performance. (3) split Communication Failure into two separate categories, one for 'Carrier' and one for 'non-Carrier' to improve the usefulness of the metrics regarding Protection System performance. (4) eliminate the TADS and GADS data submittals. Instead request the total number of operations at each Equipment Voltage level because this is a more effective means of gathering the information for all Protection System operations. (5) Align Attachment 1 with the present reporting template to ease burden on entities. (6) We also believe that (a) Declarations should be included in the Attachment 1

Organization	Yes or No	Question 5 Comment
		reporting template and (7) (b) The reporting template should be contrived so that it automatically documents and thus provides much of the evidence required by the standard.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Essential Power, LLC	No	1) There are too many classification choices in the "Resolution Status" field of the report form. An equally effective status report can be delivered using three choices:1) Analysis In Progress [Still Under Investigation]; 2) Analysis Completed - Corrective Action Plan Pending; 3) Corrective Action Completed [Investigation Complete, Corrective Action Complete] 2) The form for GOs should differ from that for TOs, for the following reasons:a. GOs are not in a position to respond to the last item on p.1, "Additional BES Interruptions." We know only what happens in our plants, not repercussions on the grid.b. The "slow trip" entries in the "Misoperations Category" do not apply for the majority of Misoperations reported by GOs. The presence of such categories in the draft standard appears to derive from the belief that millisecond-resolution records of Misoperations are always available from DME; but, when this equipment is present at generation plants, it is installed only at the GSU and (if the GO is the owner) the yard breaker - that is, on high-side equipment. The DME is consequently not expected to yield any useful information for Faults occurring at the generator or other low-side components. Notes should be added to PRC-004-3 and the Application Guidelines to the effect that DME downloading and speed-of-response analysis pertain at generation Facilities only when DME is present and only to incoming Faults from the grid. 3) Further, the current draft standard does not dictate whether quarterly reporting to the CEA is required and enforceable, as it is currently (the term "will" as opposed to "shall"). 4) Additionally, there is no reference to reporting in a manner outlined by the

Organization	Yes or No	Question 5 Comment
		CEA/RRO. The use of a common "form" is needed to achieve the usefulness and effectiveness of these data submittals.
Response: Thank you for your comments. **Please read the Summary Consideration for Question 5.**		
Western Small Entity Comment Group	Yes	But we do not like the new format. Having each event on an individual line made the information easier and quicker to find. The new format has each event spread over many rows and columns.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Project 2010-05.1	Yes	FirstEnergy (FE) agrees with the concept that this data is necessary for analysis, however, by listing the Attachment within the Compliance section would lead one to believe that Attachment 1 was part of the standard, when in actuality it is not.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
American Electric Power	Yes	We encourage the SDT to ensure this form is consistent with SPCS form.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the data listing is generally consistent with the existing process.
Response: Thank you for your comment.		

Organization	Yes or No	Question 5 Comment
Please read the Summary Consideration for Question 5.		
PSEG	Yes	Metrics can be developed, but the team should describe what metrics it envisions and how those metric will be used.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
NextEra Energy Inc.	Yes	NextEra has no issue with the information requested or the format, but requests that NERC and the regions all use the same form for the collection of misoperation data.
Response: Thank you for your comment. **Please read the Summary Consideration for Question 5.**		
Associated Electric Cooperative Inc - JRO00088	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 5 Comment
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	
Western Area Power Administration	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
Manitoba Hydro	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
LCRA Transmission Services Corporation	Yes	
Dairyland Power Cooperative	Yes	

Organization	Yes or No	Question 5 Comment
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)

6. **The team has included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific reasons why not and alternative recommendations and justifications.**

Summary Consideration:

A large percentage of the entities that commented stated that the 10-day intervals between severity levels for Requirements R1, R2, or R3 were too short. The drafting team used the NERC guideline: "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." However, based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.

Several commenters questioned the 'High' VRF for Requirement R4 because Part 4.2 appeared to be administrative. The drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The VRF was not changed.

Several commenters noted that the VSLs for Requirements R2, R3, and R4 were not always consistent with the language in the requirements and the drafting team corrected these inconsistencies.

A few commenters suggested that the VSLs for Requirement R1 should be based on multiple operations or a percentage of operations missed rather than the amount of time by which they were missed. The drafting team responded that: "Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level 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."

A couple of commenters were concerned that the requirements didn't consider the varying level of impact that different types of Misoperations can have on the BES. The drafting team responded that the NERC Sanction Guidelines allow NERC or the regional entity to consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor when evaluating a violation.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	There should be no respopnse to this question. I can't deselect either "Yes" or "No".
Response: Thank you for your comment.		
Western Small Entity Comment Group	No	Violation risk factors should be entity specific based on the equipment owned and their place in the system and not on the requirement alone.
Response: Thank you for your comment. **The FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement." As the description indicates, each VRF is associated with a requirement and not on the equipment owned and their place in the system.**		
Associated Electric Cooperative Inc - JRO00088	No	On Page 11, the Severe VSL column's phrase containing "OR The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2. ":Append: "and the Responsible entity failed to perform the subsequent R1 Part 1.3 as well."Rationale: We fail to see the reason for severity of impact otherwise.
Response: Thank you for your comment. **The drafting team revised Requirement R1 and the associated VSLs.**		
Pepco Holdings Inc & Affiliates	No	The language in the VSL's for Requirement R2 should be changed to match the language in the Requirement. The present language uses the phrase "...following the completion of the investigation or receiving notification." That phrase should be eliminated and instead the phrase "...after the cause of the misoperation has been

Organization	Yes or No	Question 6 Comment
		identified" should be inserted.
Response: Thank you for your comment. **The drafting team modified each VSL to end with the phrase "following the identification of the cause of the Misoperation."**		
Souhwest Power Pool Reliability Standards Development Team	No	Most entities will be compliant or not. 1. We don't agree that the severity level needs to be raised based on being an additional 10 days late. We would suggest revisiting this section and possibly make the interval 30 days in between a severity increase. 2. The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph 81 project that is ongoing.
Response: Thank you for your comments. **1. The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Tacoma Power	No	Under the Lower and Moderate VSLs for R3, the description ends with "...following the associated interrupting device operation " Under the High and Severe VSLs, the description ends with "...following the completion of the investigation." Was this

Organization	Yes or No	Question 6 Comment
		difference intended? It seems that there should be consistency.
Response: Thank you for your comment. **The drafting team modified the High and Severe VSLs to be consistent with the Lower and Moderate VSLs.**		
El Paso Electric	No	Based on the NERC's definition of High - Violation Risk Factor, EPE believes the assignment of High Risk to R4 does not seem to be warranted. R4 combines the implementing and documentation of any corrective actions in connection with a misoperation, and does not impact the reliability of the BES. EPE believes a separation of the implementing process and documentation requirements may provide a solution.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Santee Cooper	No	As stated in Question 3, we do not feel the timetables involved are needed for ensuring operations and misoperations are handled appropriately. That being said, for R1 and R3, 30 days is a quick change from Lower to Severe. Suggest making the change for R1 and R3 should be proportionate to R2 (about 50%).
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		

Organization	Yes or No	Question 6 Comment
Dominion	No	a). For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. b). By having specific 60 and 120 day requirements, this brings additional violation complexity to the process and is unessary. As stated previously, use same approach as COM 003 and eliminate the daily requirements. c). VSLs will need to address when a Misoperation is caused by an entity having no equipment operations where initial analysis is by first party and remainder of requirements apply to second party. (See comments to Question 4)
Response: Thank you for your comments. **a). The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **b). Thank you for your comment.** **c). The drafting team believes the revised requirements, measures and VSLs adequately address your concern.**		
Luminant	No	Change accordingly to the response to Q2 and Q3.
Response: Thank you for your comment. **The VSLs were adjusted to be congruent with the revised requirements.**		

Organization	Yes or No	Question 6 Comment
SERC Protection and Control Subcommittee (PCS)	No	While the SERC PCS does not see the need for timetables (see comment under #3), if they are put in place, we offer the following recommendations: 1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. Please make them more consistent with the requirement duration. As a comparison, R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. 2) R2 VRF measures duration from 'completion of the investigation or receiving notification' but R2 itself measures from 'identifying the cause(s) of each Misoperation'. Please change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.
Response: Thank you for your comments. **1) The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2) Based on comments, the drafting team modified the Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**		
ACES Power Marketing Standards Collaborators	No	(1) We agree with the classification of the VRFs. (2) The time horizons for R2, R3, and R4 are Long-term Planning, which is a planning horizon of one year or longer. There is a gap in the time horizons - the 180 day mark is longer than seasonal but shorter than 1 year. We recommend classifying these standards as Operations Planning, which would be consistent with R1.

Organization	Yes or No	Question 6 Comment
		(3) The violation severity level for R1 increases based on arbitrary timelines. It is conceivable that an entity could identify and review a Misoperation on day 150 (which would be a severe VSL) and complete the CAP 20 days after, which would still be within the 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and if an entity did not do anything that would be a reasonable justification for severe. (4) Also in R1 VSL, the second paragraph in the Lower section is almost identical to the second paragraph in severe, which is confusing and could lead to inconsistent application. We recommend revising the R1 VSLs for clarity and would like the SDT to consider creating VSLs that determine the severity level if R1 and R2 are not completed in a certain period of time. (5) Our concerns with the R2 VSL are similar to paragraph (3) above. It is conceivable that an entity could identify and review a Misoperation on day 30 and complete the CAP 70 days after (which would be a severe VSL), and would still be well within the total 180 day timeframe (established by R1 with R2). The VSLs do not reflect the spirit of the standard and need to be revised with reasonable timelines. If R1 was not complete within 180 days, then that would be more justifiable for a high VSL and not doing anything would be a reasonable justification for severe.

Response: Thank you for your comments.

(1) Thank you for your support.

(2) Requirements R2, R3, and R4 have dual Time Horizons of Operations Planning and Long-Term Planning. The drafting team recognizes that there is a gap in the VSL time frames, but addressing the timeframe gap is outside the scope of the drafting team.

(3) The drafting team believes the timeframes in the requirements are not arbitrary, but were established considering the impacts of seasonal weather-related operations. The timeframe associated with each VSL pertains to the individual requirement, and do not relate to the actions of other requirements and their associated VSLs.

Organization	Yes or No	Question 6 Comment
(4) The drafting team believes the two VSLs are sufficiently different such that no inconsistent application will occur. **(5) The timeframe associated with each VSL pertains to the individual requirement, and does not relate to the actions of other requirements and their associated VSLs.**		
Bonneville Power Administration	No	The time limits between the different VSL's are arbitrary. For example, if an operation is analyzed within 120 days there is no violation, but if it is analyzed after more than 150 days, only 25% later, it is a severe violation. BPA believes it would be more appropriate to have only a single violation severity level of low or moderate after the 120 day deadline.
Response: Thank you for your comments. **The NERC Violation Severity Guidelines do not allow for a single VSL that is Lower or Moderate; from page 2 "Requirements: If the requirement is a "pass or fail" type requirement or when any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement, then the single VSL must be "Severe". (This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – the impact to reliability should be addressed through the VRF, not the VSL.)"** **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
GTC	No	GTC does not agree with VSL R4 Lower VSL - Concerned statement "records were incomplete" is an opened quantifier and is not auditable, leaves to much room for interpretation for auditor. Request statement like "did not contain signed-off evidence of any revision(s) or completion of defined actionable items defined in document".

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
ISO/RTO Standards Review Committee	No	As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES. For example, an operation of an auxililary tripping relay for tap configuration substation does not have the same BES impact as a bus differential relay scheme in a full ring configuration substation.
Response: Thank you for your comment. **The FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement."** **However, the NERC Sanction Guidelines state that "Violation Risk Factors are assigned to standards' requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes that the NERC Sanction Guidelines address your comment.**		
JEA	No	1. This increases from low to severe by 10 day increments so if it takes you 5 months instead of 4 you are at a severe VSL. 2. Also missing just one review results in a severe level. Also not notifying an adjacent entity that you think they may have contributed to the problem is a severe violation - the severity should be based on the number of occurances. We think that 30 day increments are appropriate and severity levels should also be

Organization	Yes or No	Question 6 Comment
		based on the percentage of missed reviews such as 1%, 2%, 5%.
Response: Thank you for your comments. 1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** 2. **Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level 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 NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."**		
TVA Transmission Operations and Maintenance	No	The limits and time horizons are too restrictive and do not take into account if an entity is making a good faith attempt to investigate a misoperation and for reasons outside of its control, cannot meet the arbitrary numbers in this draft. There needs to be exemptions made for the safe operation of the transmission system to override the limits. Maybe some sort of deferral process with proposed dates to replace the time horizons when system conditions cannot support the necessary work required to investigate and correct.
Response: Thank you for your comments. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		

Organization	Yes or No	Question 6 Comment
Please note that the timeframes for the Corrective Action Plan or action plan are for development only and not for implementation.		
Nebraska Public Power District	No	1. Other comments and concerns stated for R1.1 would need to be addressed and modified in the VSLs. 2. The severe violation for failure to notifiy and provide requested investigative information should be removed. This will be difficult to audit and has a subjective nature. It also puts a burden on the sending utitilty where all aspects are not under their control especially if the receiver does not want to cooperate.
Response: Thank you for your comments. **1. The VSLs were adjusted to be congruent with the revised requirements.** **2. The drafting team believes that the VSLs for Requirement 1, Part 1.1 regarding the notification to the other entity and the response to the other entity are appropriate. No change was made based on this comment.**		
PacifiCorp	No	PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a "Lower" and a "Severe" VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional 30 days late should not increase the VSL from "Lower" to "Severe." A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity's failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL.**		

Organization	Yes or No	Question 6 Comment
To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.		
Western Area Power Administration	No	The metrics seem arbitrary and not linked to possible risk to the BES.
Response: Thank you for your comment. **The FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement."** **However, the NERC Sanction Guidelines states that "Violation Risk Factors are assigned to standards' requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes the NERC Sanction Guidelines address your comment.**		
Southern Company	No	a)VSLsfor the draft R1 and R2 should change based on the new time frame suggested in our response to Q2 and Q3. For the CAP development and documentation, keep only the "failed to develop..." as a VSL. b) The VSL shown for R3 reveals that R3 is not needed - the development and documentation of the CAP is the subject of the drafted R2, and the implementation of a CAP is the subject of the drafted R4. c) The severe VSL for R3 incorrectly lists implementation of the CAP as a measure - implementation of the CAP is the subject of the draft Requirement 4.â€‚â€‚ d) We suggest that the Severe VSL for R4 be the only VSL for that requirement.

Organization	Yes or No	Question 6 Comment
		e) The VRF for R4 is too high. It should match the other requirements - if the CAP is not implemented, there is no additional risk than if a Protection System operation is not reviewed. f) A new requirement for reporting to the RE should carry a low VRF.
Response: Thank you for your comment. **a) The VSLs were adjusted to be congruent with the revised requirements. The drafting team believes that a time frame for development of the Corrective Action Plan or action plan is appropriate to include in the VSLs.** **b) The drafting team disagrees. Requirement R3 is associated with an "action plan" that is required when a specific cause of the Misoperation is not discovered and not based on a Corrective Action Plan as defined in the NERC Glossary of Terms.** **c) Based on your comment, the drafting team removed the implementation component of the action plan from the Severe VSL for Requirement R3.** **d) Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.** **e) The FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement."** **However, the NERC Sanction Guidelines states that "Violation Risk Factors are assigned to standards' requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes the NERC Sanction Guidelines address your comment.** **f) The reporting obligations have been removed from the standard..**		
Okanogan PUD	No	In the VSL for R4 this is listed as a High Severity. We feel that small entities which are

Organization	Yes or No	Question 6 Comment
		on a 6 year audit cycle could have issues with document retention. Small entities 6 year entities do not have the resources to have the backup systems that larger entities. Also 6 year entities do not have the space and budget to ensure all documents are retained.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised. The difference in audit cycles for different sized entities is outside the scope of the drafting team.**		
ITC	No	1. The interval between severity levels should be 30 days instead of 10 days. 2. For the lower severity level associated with R4, the standard of 'incomplete records' is subjective unless M4 is revised.
Response: Thank you for your comments. **1. The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
seattle city light	No	1. For R1, R2 and R3, SCL does not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the "Find,

Organization	Yes or No	Question 6 Comment
		Fix, and Track" category or non-zero-defect treatment, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. 2. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement.
Response: Thank you for your comment. 1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its "Violation Severity Level Guidelines." Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** 2. **Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level 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 NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."**		
Cleco Corporation	No	It seems to us the SDT spends too much time on the VRFs and VSLs. An Entity is either compliant or not and verifying whether you are within so many days seems perculiar. 1. Why was ten days choosen and not 30 or 45 days? 2. The high VRF in requirement R4 applies to both 4.1 and 4.2. We agree that 4.1 should be a high VRF since it has to do with the actual implementation. On the other hand 4.2 seems to be purely administrative dealing only with maintaining implementation records. We don't agree that this is a high VRF. In fact we question if it should even be included in this requirement and should fall under the Paragraph

Organization	Yes or No	Question 6 Comment
		81 project that is ongoing.
Response: Thank you for your comments. **1. The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **2. Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Wisconsin Electric	No	We suggest that the Time Horizon for all four Requirements should be the same, "Operations Planning, Long-Term Planning". R1 is presently listed as Operations Assessment, Operations Planning.
Response: Thank you for your comment. **The drafting team believes depending on the impact of the operation, this requirement may fall under the Operations Assessment time horizon and as such, no change was made to the standard.**		
Manitoba Hydro	No	Many of the requirements in this standard appear to be administrative or documentation based. It is therefore surprising to us that the VRFs and VSLs would be so high. As we understood it, NERC would like to eliminate documentation-based requirements. Was that not the purpose of Project 2013-02 Paragraph 81? For documentation-based requirements, the VSLs appear to have very little leeway. 1. For example, in R1 if an entity is 20 days late the VSL jumps to High. This seems disproportionate in comparison to the insignificant reliability impact that delaying the review by 20 days will have on the BES. An entity should be late by significantly more time to warrant going up to a High or Severe VSL.

Organization	Yes or No	Question 6 Comment
		2. In terms of the VRFs, we do not agree that structured misoperation reporting will reduce misoperations and therefore feel that the VRFs should be lowered from Medium (R1, R2, R3) and High (R4) to Low and Medium. 3. VSLs - R2 - The time frames should run from the 'identification of the cause(s) of each Misoperation' rather than completion of the investigation or receiving notification to be consistent with the requirement language. 4. VSLs - R3 - High VSL and Severe VSL - the timeframes should run from the 'associated interrupting device operation' not the completion of the investigation to be consistent with the requirement language. 5. Severe VSL - the word 'in' is missing from the first paragraph in describing more than 210 calendar days. 'Implement' should be removed from the second paragraph as this is not required in the language of the requirement; the 'ed' should be removed from documented.

Response: Thank you for your comments.

1. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**
2. **The reporting obligations have been removed from the standard and no changes were made to the Violation Risk Factors.**
3. **Based on comments, the drafting team modified the Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**
4. **The drafting team modified the High and Severe VSLs to be consistent with the Lower and Moderate VSLs in Requirement R3.**
5. **The drafting team made the suggested changes.**

Organization	Yes or No	Question 6 Comment
American Electric Power	No	1. The R1 VSL's should use percentages to determine the severity level. As written, a utility performing 99% of the identification, review, notification, designation and documentation correctly would receive a severe violation. 2. In the R4 VSL's, "The responsible entity failed to maintain records of a CAP or action plan" should be moved from severe to medium. The penalty for failing to document should be less than the penalty for failing to implement.
Response: Thank you for your comments. 1. **Pursuant to Guideline 4 in FERC's Order on Violation Severity Levels document, "Violation Severity Level 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 NERC Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations."** 2. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Portland General Electric Company	No	Severe VSLs should not be applied for lateness, only for failure to perform the required activity.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
LCRA Transmission Services Corporation	No	1. For R1, R2 and R3, we do not believe it is appropriate to increase the violation severity level based on the number of days beyond the required completion date. A company could have a great process and record of analyzing and correcting

Organization	Yes or No	Question 6 Comment
		misoperations and receive a severe violation for a clerical error. Any potential violations in this area related to documentation and/or timing may fall into the “Find, Fix, and Track” category, and the VRF and VSL levels ought to be set in order to allow for the FFT process to apply. It would be more appropriate to issue a lower VSL for a single instance of missing the required completion date or lacking documentation for a single event. A moderate or high VSL should be issued for missing multiple completion dates or lacking documentation in several areas. A severe VSL should be issued for not having a program or any evidence of achieving the requirement. We have no suggested change for R4.
Response: Thank you for your comment. **The drafting team used the NERC-recommended “Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended” description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the ‘LOWER’ VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
MISO	No	As a general comment on VRFs and VSLs, there does not seem to be a correlation between how a lack of address of a particular protection system operation is tied to how severe an impact it had or may have on the reliability of the BES.
Response: Thank you for your comment. **The FERC-approved description of “Violation Risk Factor” is “Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement.”** **However, the NERC Sanction Guidelines states that “Violation Risk Factors are assigned to standards’ requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the**		

Organization	Yes or No	Question 6 Comment
violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes the NERC Sanction Guidelines address your comment.		
Modesto Irrigation District	No	VSL levels should comport with the amount of errors/missed completions discovered, not time delay for a single missed completion.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
Liberty Electric Power LLC	No	Suggest removing R4 lower - too subjective.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
Cogentrix Energy, LLC	No	Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator	No	We agree with the VRFs, VSLs and Time Horizons for R1, R2 and R3 but do not agree with the VRF and VSL for R4.We fully endorse the concept that a CAP needs to be implemented to ensure correct operations of the protective relay in question. However, not complying with R1 or R2 will result in not having a CAP to begin with. For this reason, we are unable to support a resulting requirement (R4) having a higher VRF than the prerequisite requirement at the front end. 1. We therefore suggest to change the VRF for R4 to a MEDIUM. 2. We also disagree with "The responsible entity failed to maintain records of a CAP or action plan." in R4 to be assigned a SEVERE VSL. The main intent of R4 is to implement the CAP, whose non-compliance warrants a SEVERE VSL. However, having implemented the CAP meets the main intent of R4 and hence missing the needed documentation does not contribute to adverse reliability impact. We therefore suggest the VSL for Part 4.2 to be a LOWER, or a MEDIUM at most.

Response: Thank you for your comment.

1. **The drafting team disagrees and declines to make the suggested change. The FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement."**

   However, the NERC Sanction Guidelines states that "Violation Risk Factors are assigned to standards' requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes the NERC Sanction Guidelines address your comment.

2. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects**

Organization	Yes or No	Question 6 Comment
from the requirement. The associated VSLs were also revised.		
NextEra Energy Inc.	No	NextEra disagrees with the approach taken in the VSLs that provides a range of days to determine the severity of the violation. The importance of investing and implementing a correct action plan for a misoperation varies on the type of misoperation and the need or not to implement a corrective action to address reliability. NextEra favors all aspects of the Reliability Standards moving to a risk, results based approach, including VSLs. Thus, the VSLs should be re-drafted to measure whether an entity has timely implemented a corrective action plan for misoperations that pose a risk to reliability, with consideration of the level of the risk and other factors such as complexity of the issue, costs and outages, etc.
Response: Thank you for your comment. **The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.**		
Ameren Services	No	(1) For R1 and R3 the escalation from Lower to Severe VSL in just 30 days is too short. We suggest that the SDT make them more consistent with the requirement duration. As a comparison R2 escalates in 30 days, which is 50% of the time limit. We recommend keeping the 50% consistent for escalation to Severe with a limit of 210 days for R1 and 270 days for R3. (2) R2 VRF measures duration from 'completion of the investigation or receiving notification' but R2 itself measures from 'identifying the cause(s) of each Misoperation'. We suggest t that the SDT change the VRF language to match R2 itself. The only notification we see is in R1, and it is inappropriate to measure CAP development duration from the time a component is only suspected.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. **(1) The drafting team used the NERC-recommended "Increments for Tardiness - Where there is a requirement with timing as an element that includes the number of days for delivering a product, identify a reasonable delay in delivering that product that would have only a minor impact on achieving the intent of the requirement and use that as the starting point for the Lower VSL. To develop the Moderate, High, and Severe VSLs, 10-day increments are recommended" description that is in its Violation Severity Level Guidelines. Based on stakeholder comments, the drafting team modified the tardiness time period in the 'LOWER' VSLs for Requirements R1 and R3 to 30 days and kept the 10-day increments for the increasing VSLs.** **(2) Based on comments, the drafting team modified Requirement R2 VSLs to be measured from the date of "identifying the cause(s) of each Misoperation."**		
Essential Power, LLC	No	Better clarity for the lower VSL associated with R4 should be provided. The term "incomplete" is too ambiguous. The current language leaves determination of "completeness" of documentation up to the auditor.
Response: Thank you for your comment. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement. The associated VSLs were also revised.**		
PSEG		We did not focus on the VRFs and VSLs and have no comments
Response: Thank you.		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Response: Thank you.		
Exelon Corp.	Yes	o Please confirm that the Application Guidelines material will be kept with the standard. One example of why this is important is so that the statement regarding

Organization	Yes or No	Question 6 Comment
		natural disasters and extenuating circumstances is included. Specifically, the Application Guidelines currently contain the following: “In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.”
Response: Thank you for your comment. **This material will be retained in the Guidelines and Technical Basis section of the standard.**		
Texas Reliability Entity	Yes	We generally agree, however the Severe VSL for R1 includes “and failed to notify and provide requested investigative information” but it doesn’t address the situation where the entity provided notification, but failed to provide “requested investigative information.” Also, the R1 VSL is overly complicated, perhaps showing that there are too many different elements in R1.
Response: Thank you for your comment. **Based on the comment, the drafting team modified the Severe VSL for Requirement R1 to state “…and failed to notify or provide requested investigative information…”**		
Detroit Edison	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	

Organization	Yes or No	Question 6 Comment
Southwest Power Pool Regional Entity	Yes	
Operational Compliance	Yes	
National Grid	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 6 Comment
The United Illuminating Company	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery	Yes	

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

Summary Consideration:

Several commenters suggested that Measure 1 should align more with the reference information contained in the Guidelines and Technical Basis section of the standard. The drafting team responded by modifying Measure M1 for clarity and affirming that the Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.

Some commenters were confused by the boiler plate language in the Evidence Retention section while other commenters wanted the evidence retention periods shortened. The drafting team responded by removing the boiler plate sentence from the standard (first paragraph of C 1.2 Evidence Retention) that appeared to conflict with the "since the last audit" language in the second paragraph. The drafting team also reiterated that the evidence retention period should begin with the completion of the last audit period.

Some commenters in general believed Measures M1 and M4 were too restrictive. The drafting team revised the measures such that they list the minimum evidence required (if any) and provide examples of other acceptable evidence.

A few commenters requested more clarity regarding evidence retention for circumstances that crossed audit periods. The drafting team responded by adding the following language to Section C 1.2 "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the interrupting device operation occurred prior to the current audit period."

Organization	Yes or No	Question 7 Comment
Western Small Entity Comment Group	No	We disagree with M1 for the same reason we disagree with R1 in Q2 above.

Response: Thank you for your comment.

The drafting team believes that reviewing every operation is the only way to be sure that Misoperations are not missed. The extent of the review should be relevant to the operation.

Organization	Yes or No	Question 7 Comment
Pepco Holdings Inc & Affiliates	No	1. The proposed data retention requirements seem reasonable. However, the following comments are offered in order to improve clarity and avoid confusion regarding the wording of Measures M1 and M2. 1) The wording on Measure M1 should be revised to substitute Requirement numbers in place of Part numbers. For example, it should read “shall have evidence for Requirement R1.1 that....” Instead of “shall have evidence for Part 1.1 that....” 2. In addition, because the list of evidence is not all inclusive it should end with the phrase “or other records”. For example, “but is not limited to dated lists, logs, databases, or other records, that document...” 3. Measurement M2 requires evidence which must include a “dated CAP”. It is unclear what a “dated CAP” means. Does it refer to the date the CAP was developed; the date the CAP is proposed to be completed by; or both? This needs to be clarified.
Response: Thank you for your comments. **1. The drafting team is using the current NERC format, there are Requirements and Parts.** **2. The drafting team included the lead in statement “that may include, but is not limited to” to allow for inclusion of other types of acceptable evidence.** **3. The drafting team intends this to be the date the CAP development was formalized.**		
Tacoma Power	No	1. Referring to M4, change “...that must include...” to “...that may include...” 2. Referring to Evidence Retention, the first paragraph appears to conflict with the second. In the first paragraph, the draft standard says, “For instances where the evidence retention period specified below is shorter than the time since the last audit...” However, in the second paragraph, the draft standard says “...shall keep data or evidence to show compliance with...since the last audit...” Given the language in the second paragraph, how can the evidence retention period be less

Organization	Yes or No	Question 7 Comment
		than the time since the last audit, as the first paragraph suggests may be possible?
Response: Thank you for your comments. 1. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.** 2. **The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph.**		
Dominion	No	(If requirements change, measures need to change also. See comments to Question 4)
Response: Thank you for your comment.		
Luminant	No	1. Measure M1 should not be written to include "all interrupting device operations must be logged". Luminant recommends that the measure for Part 1.1 be revised from "each interrupting device" to "each applicable interrupting device". 2. M1 measures for part 1.2 and 1.3 would be "Acceptable evidence for Part 1.2 may include, but is not limited to, electronic or written documents that indicate the owner of was notified of the event associated with the operation. Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of a dated investigation report or documented findings for Misoperation."
Response: Thank you for your comments. 1. **The drafting team made the suggested change to Measure M1.** 2. **The drafting team modified Measure M1.**		
ACES Power Marketing Standards Collaborators	No	The SDT referenced NERC Rules of Procedure, Appendix 4C (CMEP), Section 3.1.4.2 Period Covered for compliance data retention to begin with the day after the prior Compliance Audit and ending with the End Date for the Compliance Audit. However,

Organization	Yes or No	Question 7 Comment
		the SDT did not include the final two sentences in Section 3.1.4.2, which states: "However, if a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard. However, in such cases, the Compliance Enforcement Authority will require the Registered Entity to demonstrate compliance through other means." Six years is excessive to maintain records for Corrective Action Plans. The SDT is within the bounds of the NERC Rules of Procedure to shorten that amount of time. We recommend three years for data retention for Correction Action Plans.
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period. The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph.**		
PPL Corporation NERC Registered Affiliates	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). By including different wording for a requirement in two separate documents, it creates ambiguity as to what is required by the Reliability Standard to demonstrate compliance. These two documents should be in seamless agreement.
Response: Thank you for your comment. **The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
Project 2010-05.1	No	For M4, FE would prefer to rewrite to the following: "Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that may include, but is not limited to, "

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Bonneville Power Administration	No	The language of M4 is that the evidence for R4 must include a list of five items, and the last item in the list is linked with "or". It is not clear if the evidence must include all five items in the list, or if only one item is required. Please clarify.
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Nebraska Public Power District	No	As mentioned above there are concerns with requirement R1.1 and M1. See comments for question 5.
Response: Thank you for your comment. **See our response for question 5.**		
Southern Company	No	1. The first paragraph of compliance Section 1.2 Evidence Retention is not needed and should be removed. (It is redundant to the second paragraph.) 2. M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Response: Thank you for your comments.		

Organization	Yes or No	Question 7 Comment
1. **The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the second paragraph.** 2. **The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
Okanogan PUD	No	As stated in Questin 6, we feel that a 6 year data retention policy could prove onerous to small entities. We would prefer a much smaller data retention policy, such as 3 years (which would be the retetion period of large entities.
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period.**		
ITC	No	M1, M2, M3 seem sufficient. M4 is unclear. Please clarify. The following would be clearer. M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include dated electronic or hard copy records that document the implementation, completion and any revision to each CAP or action plan. Acceptable records include, but are not limited to:- Dated work management program records- Dated Work orders- Dated Maintenance Records
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
Wisconsin Electric	No	In M1, the acceptable evidence for Parts 1.1 and 1.2 should also include "electronic or hard copy records", as it does for the notification required by Part 1.1.
Response: Thank you for your comment. **The drafting team modified Measure M1 as requested.**		

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	No	1. In R1 and its associated measure, the measure implies that more work needs to be done in terms of the level of review that the requirement itself. The requirement is vague and could be interpreted differently by different people. This requirement and measure should both be re-worded to be more clear and consistent. (See related comments under Question 2.) 2. Since for each Protection System operation, either R2 or R3 would apply, the words “As Applicable” should be added to these measures. 3. Also, in M1 the wording “Part 1.1” is used. This should say “Requirement R1.1”.
Response: Thank you for your comments. **1. The drafting team revised Requirement R1 and Measure M1. Please review the new requirement and measure.** **2. The lead in statement in each requirement gives the conditions when that requirement is applicable. The measure is associated with each requirement so if the requirement is not applicable then the measure is not applicable.** **3. The drafting team is using the current NERC format, there are Requirements and Parts.**		
Exelon Corp.	No	1. Measure M4 - change “must include” to “could include”. So the new wording is as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that could include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan, completion of actions and revisions for each CAP or action plan; dated work management program records, dated work orders, or dated maintenance records.”
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		

Organization	Yes or No	Question 7 Comment
City of Austin dba Austin Energy	No	The phrase “must include” in measure 4 should likely be “may include.”
Response: Thank you for your comment. **The drafting team revised Measure M4 such that it lists the minimum evidence required and provides examples of other acceptable evidence.**		
PSEG	No	We have proposed alternative Measures in #2 and #3 above and in #9 below. The Data Retention language is acceptable.
Response: Thank you for your comment. **See our responses to the associated questions.**		
Liberty Electric Power LLC	No	Disagree with the requirement for "each interrupting device activation" list - some activations are normal shutdown activations.
Response: Thank you for your comment. **The existing phrase “caused by a Protection System operation” excludes operation of devices initiated by operators. The use of reverse power relays for generator shutdown is excluded from the operations review. See the Guidelines and Technical Basis section of the standard referencing category (6) of the definition of Misoperation.**		
Cogentrix Energy, LLC	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it’s too late to do anything about it that our lists, logs etc do not constitute sufficient evidence.
Response: Thank you for your comment.		

Organization	Yes or No	Question 7 Comment
The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.		
City of Tallahassee	No	I do not see any reference to Data Retention.
Response: Thank you for your comment. **See Section C 1.2 of the draft standard.**		
NextEra Energy Inc.	No	NextEra disagrees with the data retention periods, given that it is also submitting quarterly reports. Specifically, from a monitoring and compliance perspective, there should be no need to maintain all data in between audits if the entity is also submitting quarterly reports. Instead, the entity should only be required to maintain one years worth of data. Since, at any time, a regional entity can via a spot check or a compliance audit review data to access compliance, it seems redundant and onerous to require that the entity stockpile three to six years of data related to misoperatrions depending on their audit cycle. Moreover, such a data retention requirement seems to be inconsistent with NERC's movement to a risk and results based approach rather than a review of past evidence and a check list approach to compliance. Accordingly, NextEra requests that the data retention be reduced to only one year.
Response: Thank you for your comment. **The reporting obligations have been removed from the standard. The drafting team believes the evidence retention period should begin with the completion of the last audit period.**		
Essential Power, LLC	No	M1 generically references lists, logs and databases, while the Application Guidelines cite much more specific evidence (sequence of events, relay targets, summary of DME records). These two documents should be in seamless agreement; we need to know specifically what will and will not be required when our records are audited, as opposed to being told when it's too late to do anything about it that our lists, logs etc

Organization	Yes or No	Question 7 Comment
		do not constitute sufficient evidence.
Response: Thank you for your comment. **The drafting team modified Measure M1 for clarity. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable and serves only as additional reference information.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Response: Thank you.		
SERC Protection and Control Subcommittee (PCS)	Yes	1) Please clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the last audit.
Response: Thank you for your comment. **The drafting team added the following language to Section C 1.2 to address your concern "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the interrupting device operation occurred prior to the current audit period."**		
Southwest Power Pool Regional Entity	Yes	In Section C 1.2, the following sentence does not seem to make sense because there are no shorter time periods specified: "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."
Response: Thank you for your comment. **The drafting team believes the evidence retention period should begin with the completion of the last audit period. The drafting team removed the boiler plate sentence from the standard that appeared to conflict with the "since the last audit" language in the**		

Organization	Yes or No	Question 7 Comment
second paragraph.		
Sacramento Municipal Utility District	Yes	SMUD also encourages the development and concurrent posting of the Reliability Standard Audit Worksheet with the next standard posting.
Response: Thank you for your comment. **Your comment was forwarded to NERC staff.**		
Ameren Services	Yes	We suggest that the SDT clarify that an entity is to retain evidence for all Misoperations with an open investigation, action plan, or CAP since the last audit even if the interrupting device operation occurred before the last audit.
Response: Thank you for your comment. **The drafting team added the following language to Section C 1.2 to address your concern "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the interrupting device operation occurred prior to the current audit period."**		
Northeast Power Coordinating Council	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 7 Comment
Colorado Springs Utilities	Yes	
Duke Energy	Yes	
GTC	Yes	
Operational Compliance	Yes	
TVA Transmission Operations and Maintenance	Yes	
PacifiCorp	Yes	
Western Area Power Administration	Yes	
National Grid	Yes	
seattle city light	Yes	
Cleco Corporation	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
American Electric Power	Yes	
Utility System Efficiencies, Inc.	Yes	

Organization	Yes or No	Question 7 Comment
Idaho Power Co.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services Corporation	Yes	
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
The United Illuminating Company	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	

8. The team has included an Implementation Plan with this posting. Do you agree with the changes? If not, please provide specific suggestions for improvement.

Summary Consideration:

Numerous commenters pointed out that the Implementation Plan did not reflect the twelve month implementation period established with the July posting. The drafting team modified the effective date to be "twelve months beyond the date that this standard is approved..."

Numerous commenters questioned how Protection System operations, Misoperations, CAPs, and reporting requirements will be transitioned from PRC-004-2a to PRC-004-3. The drafting team responded that the Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.

Organization	Yes or No	Question 8 Comment
Pepco Holdings Inc & Affiliates	No	We agree with the timetable associated with the implementation of the new definition of a misoperation and for implementing the requirements in PRC-004-3. However, the following changes in the commentary included in the Implementation Plan should be made: 1) Re-word the definition of misoperation in accordance with the comments that we provided in Question 1 in this form. 2) Modify the list of "Facilities not included" to add Underfrequency Load Shedding (UFLS). 3) Modify the list of "Facilities not included" to expand on the Control section as follows: "Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)" Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to

Organization	Yes or No	Question 8 Comment
		have to refer to the additional Guidelines and Technical Basis for most applications.
Response: Thank you for your comments. 1. **See our response to your comment in Question 1. The Implementation Plan will reflect any changes to definitions or the standard.** 2. **Misoperation of Underfrequency Load shedding is not handled by any other NERC standard so therefore must remain part of this standard. The drafting team clarified this by adding clause 4.2.2 to Applicability Section 4.2 of the draft standard.** 3. **The drafting team modified clause 4.2.4 of Applicability Section 4.2 to state: "Non-protective functions that may be imbedded within a Protection System are excluded."**		
Dominion	No	1.) Must include a specific plan of transitioning open investigations or CAPs to new standard requirements and reporting requirements. 2.) Specifically state when all other requirements are effective.
Response: Thank you for your comments. 1. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.** 2. **The section "Implementation Plan for Requirements R1, R2, R3 and R4" states the effective date for each requirement.**		
Operational Compliance	No	Establishing the "most stringent" standard between WECC & NERC requirements will be difficult and time-consuming. Regional standards should fully complement and enhance NERC Standards. To that end, the NERC standard PRC-004 should be written such that the related WECC standards CAN fully complement and enhance it.
Response: Thank you for your comment. **Regional standards must be more stringent than the Continent-wide NERC standard. The drafting team included the following in**		

Organization	Yes or No	Question 8 Comment
the Background section of the draft standard: "Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard."		
American Electric Power	No	AEP does not have problem with the implementation plan; however, the implementation duration of six months is not consistent with the response in the SDT's Consideration of Comments which indicate it is 12 months.
Response: Thank you for your comment. **The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..." as previously stated in the last Consideration of Comments.**		
Exelon Corp.	No	o Implementation date: This standard is to go into effect on the first day of the first calendar quarter, 3 months after Board of Trustees adoption. This does not allow adequate time for the necessary programmatic and procedural changes required for a large organization. Suggest more time be allowed - such as one year after Board of Trustees adoption.
Response: Thank you for your comment. **The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..."**		
The United Illuminating Company	No	The implementation plan should recognize that the Requirements will be applied to the first protection system operation that occurs AFTER the effective dates. Any operations or misoperations or corrective action plans being implemented are not subject to this Standard.
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The drafting team modified the Implementation Plan to distinguish between**		

Organization	Yes or No	Question 8 Comment
Protection System operations that occur before and after the effective date of the new standard.		
PSEG	Yes	No comments.
Ameren Services	Yes	(1) Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as Update Submittal Type once it becomes effective? (2) Six months after approval may be too short a time to modify processes and software to efficiently meet the PRC-004-3 requirements and supporting evidence.
Response: Thank you for your comments. **1. The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.** **2. The effective date in the Implementation Plan has been changed to "twelve months beyond the date that PRC-004-3 is approved..."**		
SERC Protection and Control Subcommittee (PCS)	Yes	Are Misoperations with open CAP to be transitioned from PRC-004-2a to PRC-004-3 as 'Update' Submittal Type once it becomes effective?
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.**		
ACES Power Marketing Standards Collaborators	Yes	1. Why is UFLS not excluded when UVLS is? 2. Also, are registered entities required to perform the 120-day assessment at least once before the enforceable date? Please refer to CAN-0012, which provides that if

Organization	Yes or No	Question 8 Comment
		the standard is silent to performing a periodic activity, the entity can perform the first activity after the enforceable date.
Response: Thank you for your comments. 1. **Misoperation of Underfrequency load shedding is not addressed by any other NERC standard so therefore must remain part of this standard. UVLS Misoperations are addressed in PRC-022-1.** 2. **Compliance to PRC-004-3 will not be required before the effective date of PRC-004-3.**		
Santee Cooper	Yes	Need to clarify how misoperations that are still not completed are going to be transitioned.
Response: Thank you for your comment. **The Implementation Plan provides entities 12 months to transition to the new requirements and compliance to PRC-004-3 is not required prior to the effective date of PRC-004-3. The reporting obligations have been removed from the standard, and the drafting team modified the Implementation Plan to distinguish between Protection System operations that occur before and after the effective date of the new standard.**		
City of Jacksonville Beach, FL dba/ Beaches Energy Services		(No Comment.)
Northeast Power Coordinating Council	Yes	
Western Small Entity Comment Group	Yes	
Associated Electric Cooperative Inc - JRO00088	Yes	

Organization	Yes or No	Question 8 Comment
Souhwest Power Pool Reliability Standards Development Team	Yes	
Detroit Edison	Yes	
Tacoma Power	Yes	
Luminant	Yes	
Colorado Springs Utilities	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Duke Energy	Yes	
Project 2010-05.1	Yes	
Bonneville Power Administration	Yes	
GTC	Yes	
Southwest Power Pool Regional Entity	Yes	
TVA Transmission Operations and Maintenance	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 8 Comment
Western Area Power Administration	Yes	
Southern Company	Yes	
Okanogan PUD	Yes	
National Grid	Yes	
ITC	Yes	
seattle city light	Yes	
Cleco Corporation	Yes	
Wisconsin Electric	Yes	
Tri-State G&T	Yes	
NorthWestern Energy	Yes	
Clark Public Utilities	Yes	
Utility System Efficiencies, Inc.	Yes	
Idaho Power Co.	Yes	
Portland General Electric Company	Yes	
LCRA Transmission Services	Yes	

Organization	Yes or No	Question 8 Comment
Corporation		
Ingleside Cogeneration LP	Yes	
New York Power Authority	Yes	
Dairyland Power Cooperative	Yes	
Orange and Rockland Utilities	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
Modesto Irrigation District	Yes	
US Bureau of Reclamation	Yes	
Liberty Electric Power LLC	Yes	
Los Angeles Department of Water and Power	Yes	
Consumers Energy	Yes	
Cogentrix Energy, LLC	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 8 Comment
Sacramento Municipal Utility District	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
NextEra Energy Inc.	Yes	
Essential Power, LLC	Yes	
Oncor Electric Delivery	Yes	
Kansas City Power & Light	Yes	

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

Summary Consideration:

Many commenters had questions surrounding the completion of a CAP when evaluating the possibility of a similar Misoperation at other locations. The drafting team responded with the following: "An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are completed."

A few commenters had questions surrounding the time limits associated with the requirements. An overall time limit for Requirements R1, R2 and R3 is not practical as many factors can delay the investigative findings in Requirement R1 or Requirement R4 (action plan) such as outage constraints and resource limitations. The sequential nature of the 60 days in Requirement R2 is important as Requirement R2 could follow either a Misoperation cause found in Requirement R1 or a Misoperation cause found in Requirement R4 via an 'action plan' execution. If the cause is found via an 'action plan', the entity may likely need an additional 60 days to create a CAP and is now beyond the 180 days. The Guidelines and Technical Basis section of the draft standard has been revised to add clarity for the independent 120 and 60 day timeframes.

A few commenters had questions surrounding the time limits associated with CAP duration and completion. The drafting team responded with the following: Establishing fixed time limits for the completion of CAPs is impractical because of the wide spectrum of Misoperation causes and the variety of corrective actions. A schedule or timetable is required to be included in the CAP.

A few commenters questioned the difference between a CAP and an action plan. The drafting team explained that a CAP is developed when the cause of the Misoperation and corrective actions have been determined. In instances where the entity's initial investigations do not determine the cause of the Misoperation; the entity would develop an action plan to perform more in-depth investigations. If the investigation does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close out of the Misoperation investigation process and for future reference.

Several commenters had concerns with the amount of administrative burden. To eliminate some of the administrative burden, the drafting team revised Requirement R4 and Measure M4 removing the revision tracking for a CAP or an action plan. The requirements

and associated documentation help ensure the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.

Several commenters had concerns that the standard implied additional monitoring equipment must be installed. The drafting team responded with the following: The standard does not require any additional monitoring equipment to be installed. Each responsible entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available Disturbance Monitoring Equipment.

Several commenters had concerns about the consistency of the Facilities section of the draft standard with regards to the Facilities Section of PRC-005-2, as well as the interpretation attached to the existing standard PRC-004-2a. In response, the drafting team revised the Facilities section by: 1) revising 4.2.1 to read: Protection Systems for BES Elements; 2) adding 4.2.2 which reads: Underfrequency Load Shedding (UFLS) that trips a BES Element; 3) restructuring 4.2.3 to read: Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded; and 4) revising 4.2.4 to read: Non-protective functions that may be imbedded within a Protection System are excluded.

Organization	Yes or No	Question 9 Comment
Cogentrix Energy, LLC		1. Compliance section C1.4 contains a requirement to report to the RE - this needs to be in the requirement section of the standard.
Response: Thank you for your response. **Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**		
Dominion		1. R2 introduces the idea of a CAP "that includes an evaluation of the CAP's applicability to the entity's Protections Systems at other locations". R4 states "maintain detailed implementation records of CAP including dated information surrounding any revision(s) and completion". With all this said, is the CAP complete once we evaluate "identify every location where a similar problem may exist" or is the CAP only complete when all locations are fixed? 2. There is no need to log revision(s) to the CAP. Having a current CAP available at

Organization	Yes or No	Question 9 Comment
		any point in time should be sufficient without tracking CAP changes. 3. In the Rationale for R4 it states “fully implemented”. We interpret this to mean fully evaluated and not fully fixed at all other locations?
Response: Thank you for your comment. **1 An evaluation of the CAP’s applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete.** **2 The drafting team revised Requirement R4 to eliminate the tracking aspects for CAP revisions.** **3 ‘Fully implemented’ was intended to mean all steps of the CAP or action plan have been completed. The drafting team replaced the term ‘fully implemented’ with ‘completed.’ The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete.**		
Texas Reliability Entity		(1) R2 assumes that one or more “Protection System component(s)” has previously been “identified”, but there is no preceding requirement that requires any such identification of components. R2 seems to infer that it is the owner of the component that caused the Misoperation who must act, but it is not expressly stated who is responsible for this requirement. (2) We agree with the approach of R2, however, we would suggest the following changes to wording to clarify this requirement by requiring certain elements in each Corrective Action Plan: R2. Within 60 calendar days of identifying the cause(s) of each Misoperation, each applicable Entity shall: o Develop and document a Corrective Action Plan (CAP) and work timetable to resolve the cause(s) of the Misoperation that includes the following: 1. Interim corrective actions (if any),

Organization	Yes or No	Question 9 Comment
		2. Final corrective actions, 3. An evaluation of the CAP's applicability to the entity's Protection Systems at other Facilities, 4. An evaluation of the CAP's applicability to Protection System component(s) owned by another Registered Entity (if applicable for the specific event),or o Explain in a declaration why corrective actions are either beyond the entity's control, applicable to another Registered Entity, or would reduce BES reliability. (3) In R4: Implementation of the CAP should include a time limit. We suggest re-wording R4.1 to say "Implement the CAP or action plan within 180 calendar days after developing the CAP or action plan, or per the CAP or action plan timetable, whichever is longer."

Response: Thank you for your comment.

1 **The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan.**

2 **The drafting team believes the existing wording of Requirement R2 provides adequate clarity and allows an entity to determine its appropriate response based on each individual event.**

3 **A part of each CAP or action plan is its timetable. It is the responsibility of each entity to follow the timetable once they have established it. The drafting team recognizes that during the implementation process it might be necessary to modify the original timetable and Requirement R4 allows for this. The 180 day criteria proposed would only impact a CAP or action plan with an implementation timetable of less than 180 days. If an entity discovers it is unable to meet the initial timetable they can modify their schedule to a date they can meet even if it exceeds the 180 days, making the proposed criteria unnecessary.**

Organization	Yes or No	Question 9 Comment
Ameren Services		(1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP “includes an evaluation of the CAP’s applicability to the entity’s Protection Systems at other locations.” It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period. (2) We suggest that the SDT reword C.1.4 from “Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA...” to “For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA...” This clarifies who is responsible for submitting when multiple entities are involved. (3) Attachment 1 “Action Plan/Declaration Development Date” example data should be “N/A”. (4) Application Guidelines - Reporting section on page 20 states ‘...the fourth ranked initiating cause of BES outages not related to weather was “Failed Protection System Equipment.” Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.’ While this may be true in terms of number of events, is sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, we suggest that the SDT also state: (a) the total number of non-weather related causes; b) the total number of causes; (c) its rank when BES outages related to weather are included; d) the top three non-weather related causes; (e) its rank in terms of BES unavailability; and f) the % of unavailability caused by Failed Protection

Organization	Yes or No	Question 9 Comment
		System Equipment. (5) M4 on page 8: We suggest t that the SDT replace 'must include' with 'may include' because some items do not apply to every CAP or action plan. Clearly the entity must document the implementation of each CAP and action plan, beyond that the range of documentation will vary depending on the situation. (6) Ameren agrees with and supports the comments of the SERC Protection & Control Subcommittee. (7) We suggest that the SDT augment the Application Guidelines Requirement 2 examples on page 17 to include "an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." (8) We suggest that the SDT modify the Application Guidelines Requirement 1 wording on top of page 18 to make it clear that the suggested information should only be included as appropriate. The cause of some Misoperations is quite obvious and does not need copious tests, DFR records, and the like. For example, carrier switch may've been in the wrong position. (9) Editorial comments: a) p4 Applicability box - replace 'RMS' with 'RAS'; b) p5 Background 3rd line - Misoperation should be singular.

Response: Thank you for your comment.

1 **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete.**

2 **The reporting obligations have been removed from the standard. Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**

3 **The drafting team will forward these comments to the NERC Protection System Misoperations Task Force and the NERC System Protection and Control Subcommittee for content consideration.**

Organization	Yes or No	Question 9 Comment
4 Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis. **5 The drafting team retained the 'must include' because it is the minimum evidence required for a CAP or action plan but modified the second sentence to state 'may also include.'** **6 Please see the drafting team responses to the SERC PCS comments.** **7 This type of evaluation would include items such as a relay firmware revision or an error found in an entity's "standard" protection logic that has been deployed at multiple locations. It is the responsibility of the Protection System owner to determine how wide spread the situation is and take the appropriate corrective actions. The drafting team has added example language to the Guidelines and Technical Basis section of the standard.** **8 Text revised to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'** **9 The drafting team made the corrections.**		
ACES Power Marketing Standards Collaborators		(1) There is ambiguity in R4, part 4.2, "maintaining detailed implementation records," which could be interpreted in different ways by auditors as to the degree of detail that is needed for implementation records. The measures give examples of acceptable methods to achieve compliance and therefore we recommend striking the word "detailed" from part 4.2. Further 4.2 is strictly a data retention requirement, which is administrative in nature and should be removed. This is the type of requirement that Paragraph 81 is currently in the process of retiring. (2) In part 4.2.3 of the applicability section, the SDT needs to emphasize that relay functions are not included in the definition of Protection Systems. By explicitly stating that certain non-protective functions that may be embedded within a Protection System are excluded, it could be interpreted that anything else that was not explicitly mentioned in the requirement could be included, such as sudden pressure relays. We recommend adding additional detail to this section for clarity. (3) Does the SDT intend to remove the old definition of Misoperations from the

Organization	Yes or No	Question 9 Comment
		background section? It does not need to remain as supplemental information with the passing of the new definition. We understand that certain aspects of the standard would be removed, such as the rationale boxes, but there is no mention that background section would be removed. (4) In the application guideline, Requirement R3 section, first paragraph first sentence - "If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation." This sentence needs to clarify what reasonable means. It appears from this statement that if you did not exhaust all reasonable investigations, then you should continue additional investigations, but at that point, you would be in violation of R1. The SDT needs to consider rewording this sentence, possibly striking the underlined portion of the sentence. (5) In the application guideline, Requirement R4 section, second paragraph - this paragraph is discussing the goals of R3 and we recommend moving this paragraph to the R3 section. Thank you for the opportunity to comment.

Response: Thank you for your comment.

1. **Based on comments, the drafting team revised Requirement R4 to eliminate the Parts and remove the administrative aspects from the requirement.**
2. **The drafting team revised the Facilities section of the standard based on yours and others comments.**
3. **The Background section is included in the final version of the approved standard.**
4. **Not determining a cause within 120 days would not be a violation of Requirement R1. If a cause has not been determined within the 120 days then Requirement R3 comes into play and the owner needs to develop an action plan or a declaration explaining why no further actions will be taken. The word "reasonable" is not in the requirement and is not mandatory or enforceable. The Guidelines and Technical Basis section of the standard provides information only.**
5. **The paragraph referenced in the comment discusses the action plan once it has been created in accordance with Requirement**

Organization	Yes or No	Question 9 Comment
R3. The bulk of the paragraph discusses Requirement R4 and calls for implementing the action plan and developing a CAP or declaration based on the determination of a cause via the action plan. The drafting team believes the paragraph is in the appropriate location.		
Independent Electricity System Operator		(1) There is no specific mention of UFLS and hence it is assumed that this standard applies to UFLS as well. However, there is no basis on why UFLS is included but UVLS is excluded in the Section A - 4.2 “Applicability”. There is also an apparent inconsistency between “Facilities not included” listed in section A.4.2.2 and definition related to under-voltage protection systems. The provision under 4.2 excludes the UVLS and capacitor switching from the applicability of the standard, and at the same time the definition (paragraph 2) gives as example of “other than fault”conditions the misoperation of under-voltage protection systems. (2) In the Background Section, a NOPR is mentioned but there is no specific information as to which NOPR it references. Need to add the relevant information. (3) The word “of” is missing from the bullet at the top of P.5 of the clean version.
Response: Thank you for your comment. 1 UFLS that trips a BES Element are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard “Underfrequency Load Shedding (UFLS) that trips a BES Element”. The example of under-voltage does not refer to UVLS. 2 Based on your comment, the drafting team removed the reference to the NOPR and replaced it with FERC Order No. 693. 3 The drafting team corrected the error.		
Pepco Holdings Inc & Affiliates		1) In Section 4.1.3 the wording should be changed to “Distribution Provider that owns a transmission Protection System”. This makes it consistent with the wording from previous versions of PRC-004, which recognized that it only applies to owners of Protection Systems that are applied to protect BES facilities. 2) A new Section 4.2.2.3 “Underfrequency Load Shedding (UFLS)” should be added

Organization	Yes or No	Question 9 Comment
		under the Applicability Section “Facilities not included.” Although UFLS schemes are Protection Systems covered under PRC-005 and are installed to preserve the BES from system underfrequency disturbances, they should not be included in this standard. Failing to specifically exclude them from this standard may lead to the assumption that they are by omission, included. Performance of UFLS schemes during system events are already covered in PRC-009, and as such do not need to be included in PRC-004-3. 3) Modify the list of “Facilities not included” to expand on the Control section as follows: “Control (e.g. controlled shutdown of generators, capacitor bank switching, and SVC, FACTS and HVDC control system actions. Also see Guidelines and Technical Basis section for detailed examples)” Although the list is not intended to be all inclusive, mentioning the most frequently used control systems negates the need to have to refer to the additional Guidelines and Technical Basis for most applications. 4) On page 6 of the Background section of PRC-004-3 there is a typographical error on the second bulleted item, “Analyze Misoperations of Protective Systems for Facilities ....” The word “of” is missing. 5) Also in the Background section the reason for the exclusion of UFLS should be addressed. 6) In Requirement R2 first bullet item remove the phrase “for the identified Protection System component(s)”. The term “component” should not be used, as it may lead to confusion. Individual Protection System component failures do not require a CAP unless the overall performance of the Composite Protection System for an Element was compromised. The bullet should instead read: “Develop and document a Corrective Action Plan (CAP) to address the identified misoperation that includes...”. 7) By NERC definition each CAP must contain a timeline for implementation. Requirement R4.1 requires you to complete the CAP. Does that mean that to be fully compliant the CAP must be completed within the proposed timeline stated in the

Organization	Yes or No	Question 9 Comment
		CAP? If so, there needs to be a mechanism to revise the proposed completion date when circumstances arise that prevent implementation in accordance with the originally proposed timeline (denial of facility outages, equipment delivery problems, major storm events, etc.) without being held non-compliant. 8) R4.2 “implies” that the CAP can be revised (presumably including the proposed completion date) as long as it is documented. If this is a correct interpretation of R4.2 then there is a mechanism to revise a CAP’s proposed completion date. On the other hand, this would allow the implementation of a CAP to be extended indefinitely by continuing to revise the proposed completion date. We doubt this is what the Standard Drafting Team intended. As such, the SDT may want to revisit the language dealing with revisions to a CAP.

Response: Thank you for your comment.

1 **The drafting team believes the Applicability section is clear and retains the intent of previous versions of PRC-004. In PRC-004-3, the functional entities are specified in Applicability section 4.1 and the Facilities are specified in Applicability section 4.2.**

2 **UFLS that trips a BES Element are covered by PRC-004-3. For clarity, the drafting team added the following in the included Facilities portion of the Applicability section 4.2.2 in the draft standard “Underfrequency Load Shedding (UFLS) that trips a BES Element”.**

3 **The drafting team revised the Applicability section and included the examples of non-protective functions in the Guidelines and Technical Basis section of the standard.**

4 **The drafting team corrected the error.**

5 **UFLS that trips a BES Element are covered by PRC-004-3.**

6 **Requirement R2 deals with an operation that has been determined to be a Misoperation and the cause was identified. This stage would not be reached unless the overall performance of the composite Protection System for an Element was compromised.**

7 **The drafting team agrees and revised Requirement R4.**

8 **The drafting team believes the Protection System owner should be allowed the freedom to draft and modify the CAP. The**

Organization	Yes or No	Question 9 Comment
Protection System owner has the option of writing a declaration explaining why no further action will be taken.		
Santee Cooper		1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP "includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." As it is presently handled, the entity can complete the CAP when the work at the place the misoperation took place is complete, and then the entity is responsible for its assessment/implementation at other locations (implementation of which may take a lot longer). However, the new standard needs to clearly state if this expectation is still the case, or if something different is now warranted. 2) Application Guidelines - Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 3) All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. 4) Suggest having a more general statement such as "A misoperation investigation report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation." For example, if you find a piece of equipment failed (powered down), a sequence of

Organization	Yes or No	Question 9 Comment
		events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a "may" and an "or" to the third sentence of page 18 "The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records."
Response: Thank you for your comment. 1 An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete. 2 Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis. 3 The drafting team agrees and made the suggested change. 4 Text revised to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'		
SERC Protection and Control Subcommittee (PCS)		1) R2 states that the CAP applies to the identified Protection System component(s). But then goes on to say the CAP "includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations." It is unclear whether the entity is required to take corrective actions at those other locations in order to complete the CAP. Our reading and expectation is that the entity completes the CAP, when they complete the identified work at the location of this Misoperation. We would expect the entity to initiate a program to address the other locations over some reasonable time period.

Organization	Yes or No	Question 9 Comment
		2) Please reword C.1.4 from "Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA..." to "For Misoperation(s) caused by BES Protection System it owns, each Transmission Owner, Generator Owner, and Distribution Provider will submit the data identified in PRC-004 - Attachment 1 to the CEA..." This clarifies who is responsible for submitting when multiple entities are involved. 3) Application Guidelines - Reporting section on page 20 states '...the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.' While this may be true in terms of number of events, it sensationalizes the Failed Protection System Equipment cause. In fact Failed Protection System Equipment is a very minor cause of unavailability. For full context, please also state: a) the total number of non-weather related causes; b) the top three non-weather related causes; and c) its rank in terms of BES unavailability. 4) A significant effort has been expended in developing the current PRC-004 misoperations template. The SERC PCS recommends that the SDT leverage this effort in consideration of misoperations reporting (Atta 1). 5) The SERC PCS recommends that the application guidelines be used for assessing misoperations and not for operations. 6) All references to an investigation report should be changed to read "Misoperation investigation report" or "investigation report due to misoperations". Without this change it could be interpreted that all operations require an investigation report. This section is a very good description of what data may be used in an investigation report, but, for clarity of compliance purposes, it should be a little more defined as to which part of this is compliance-related and which parts are just informative. (7) Suggest having a more general statement such as "A misoperation investigation

Organization	Yes or No	Question 9 Comment
		report should be of sufficient detail to either ascertain the cause of the misoperation or else describe the work performed/being performed to analyze the misoperation." For example, if you find a piece of equipment failed (powered down), a sequence of events or DME records are not needed to figure out the cause, and so should not be required in the Misoperation investigation report. Along those same lines, we suggest adding a "may" and an "or" to the third sentence of page 18 "The initial evidence, which may also be documented separately, may contain the sequence of events, relay targets, and/or a summary of Disturbance Monitoring Equipment (DME) records."

Response: Thank you for your comment.

1. **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. The CAP is complete when the evaluation and all actions specified by the entity in the CAP are complete. The evaluation in Requirement R2 does not require prescribing actions at other locations. If the entity prescribes actions at other locations in its CAP then the CAP is not complete until all the specified actions are complete.**
2. **The reporting obligations have been removed from the standard. Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.**
3. **Providing all the suggested detail would not improve the standard. The drafting team revised the text to minimize the emphasis.**
4. **The drafting team will forward these comments to the NERC Protection System Misoperations Task Force and the NERC System Protection and Control Subcommittee for content consideration.**
5. **There are examples in the Guidelines and Technical Basis section of the standard for accessing what is considered a misoperation and what is not considered a misoperation. The Guidelines and Technical Basis section of the standard provides information only.**
6. **The drafting team agrees and made the suggested change.**

Organization	Yes or No	Question 9 Comment
7 Text revised to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'		
Xcel Energy		1) Regarding R1.1, it is not clear which entity would report the Misoperation, or be responsible for the remaining requirements. Would it be a joint responsibility? Please consider revising the requirement to indicate that the entities must agree on which one would handle the misoperation process, while the other would support as needed. 2) Consider including RAS/SPS, UVLS, UFLS under the applicability and eliminating the standards associated with misoperations on those specific types of protection systems.
Response: Thank you for your comment. **(1) The drafting team has clarified Requirement R1 to show that the interrupting device owner will do the initial investigation and will contact other Protection System owners only if a correct operation cannot be determined. In this case, the investigative information is passed from the interrupting device owner to the other owners. The standard requires all owners to confirm whether their portions of the Protection System operated correctly or not within 120 days of the interrupting device operation. As stated in the Guidelines and Technical Basis section of the standard, the drafting team expects all owners to work jointly in making these determinations, freely sharing information with each other. Only the owner of a Protection System component that Misoperated is responsible for documenting the findings, developing a CAP or action plan.** **(2) RAS and SPS will be addressed in Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. It is beyond the scope of this team to eliminate existing standards other than PRC-003-1 and PRC-004-2a. UFLS that trips a BES Element are covered by PRC-004-3.**		
GTC		1) Why are UFLS schemes included in this standard but UVLS schemes are omitted? GTC recommends the addition UFLS be added to the list under Applicability section 4.2.2 (ex. 4.2.2.3). 2) Lastly, the overall tone of the document drives entities to focusing more labor and work on the documentation of an event than completion of a correctable action. In

Organization	Yes or No	Question 9 Comment
		addition, the dates for requirements and implementation seem to be defining how entities must perform work and does not give flexibility for entity to respond appropriately to problems. Possible to drive entities to provide a quick fix so they can close out documents instead of spending the appropriate time studying the event and define true root cause. Standard needs to measure performance by documenting events as misoperations with defining root cause. Should not cover expectations of an entity and drive them to a particular performance which may drastically change their business model and performance.
Response: Thank you for your comment. **(1) UFLS that trips a BES Element are covered by PRC-004-3. See the revised Facilities 4.2.2. The performance of UVLS schemes is covered by PRC-022-1.** **(2) The standard provides flexibility to the Protection System owners to set the timetables within their CAPs or action plans. There are also provisions to revise the timetables if the situation warrants.**		
Exelon Corp.		1) In the Introduction section, Applicability includes Distribution Provider. If this standard is for Protection Systems that are part of the BES, does a DP belong in the list of Functional Entities? 2) To what extent would an entity have to defend a determination that a system operation is considered to be a correct operation, if there is limited data to make the determination? This should be addressed in the Application Guide. 3) The Application Guidelines state that reverse power relay operations used for control of a generator (when a reverse power relay is used to trip a breaker during generator shutdown) are "not included in the definition of Misoperation and its operation would not be reviewed under this standard." Since it can be debated whether a reverse power relay is used for control or generator protection, the Application Guidelines should remove the verbiage about the "control" aspect of this relay. The Application Guidelines should just state that "expected reverse power relay operations, such as those encountered when a generator comes off-line, would

Organization	Yes or No	Question 9 Comment
		not be required to be reviewed under this standard." This comment is not intended to remove the entire Application Guidelines discussion on control aspects of relays being excluded from needing a review under this standard. Rather, the intent of this comment is to revise the Application Guidelines so as to preclude any discussion over whether a reverse power relay is a control device or a protective device - and just list the exclusions for this relay, and any similar generator relays. 4) Exelon requests that the SDT clarify within the Standard that the interrupting device itself referenced in the Standard draft is also considered an element of the Bulk Electric System. Specifically, please clarify that a device on a radial line that does not affect the BES is excluded from this requirement. Suggest that this clarification be added to the Application Guidelines. 5) PRC-004 Requirement R1 requires that each Generator Owner identify and review each Protection System operation associated with an interrupting device operation. The SDT should re-evaluate this requirement as it implies that all generating facilities have established monitoring systems that will capture such events. Although some generating units do have existing monitoring systems (such as Disturbance Monitoring Equipment) not all generating units have such capability nor are they all required to install such monitoring equipment in accordance with existing FERC approved Standards. 6) Exelon agrees with the SDT revision to remove the requirement in R1 that an entity shall have and implement a "procedure" to identify and address all Protection System Misoperations within its system and that an existing Corrective Action Program will meet the intent of the Standard; however, the SDT response to the Exelon and Constellation comments submitted in the previous draft (Consideration of Comments in response to the 6/10/11 - 7/11/11 draft) is inaccurate and warrants clarification. The original Exelon comment was: "Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the

Organization	Yes or No	Question 9 Comment
		draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management." The SDT response documented is as follows: "Thank you for your comments. These requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC." As a point of clarification, the SDT response that references Order 706-B indicates that BES electrical systems would not fall under NRC regulation. In summary, FERC Order 706-B "clarifies that the facilities within a nuclear generation plant in the United States that are not regulated by the U.S. Nuclear Regulatory Commission are subject to compliance with the eight mandatory 'CIP' Reliability Standards approved in Commission Order No. 706." In November 2010 FERC and the Nuclear Regulatory Commission (NRC) came to understand that because changes in electrical power output affect nuclear reactor core reactivity, NRC would have oversight of these "balance of plant" systems. FERC formalized this understanding in FERC Order issued March 10, 2011, Docket No. RM06-22-014, "...we find that the NRC's cyber security rule appears to cover all balance of plant, and no balance of plant at a U.S. nuclear power plant has been found to be subject to NERC's CIP Standards." It should be noted that the NRC required Corrective Action Program (regulatory requirement

Organization	Yes or No	Question 9 Comment
		information as documented above) applies to all systems, structures and components of a nuclear generating unit and therefore should be an acceptable method of complying with the revised Standard.

Response: Thank you for your comment.

1 **Distribution Providers that own Protection Systems that protect Facilities that are part of the BES are and should be included as applicable entities in this standard.**

2 **The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**

3 **The section in the Guidelines and Technical Basis section of the standard concerning reverse power relays states "…the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard." The drafting team declines to make the suggested change.**

4 **Protection Systems for Facilities that are part of the BES are included in the standard. The Applicability section, 4.2 Facilities 4.2.1 states this. The drafting team believes this adequately exempts non-BES equipment.**

5 **The standard does not require any additional monitoring equipment to be installed. Each Generator Owner must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**

6 **The drafting team continues to believe that our previous response is correct and the NERC standard does apply.**

Organization	Yes or No	Question 9 Comment
Southern Company		1) There needs to be some consistency between the proposed PRC-004, and PRC-005. How can one say a given Protection System needs to be maintained for the BES Reliability, but not necessarily operations analyzed. The Applicability of PRC-004: Protection Systems for Facilities that are part of the BES. The Applicability of PRC-005-2: 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) 2) Please clarify the PRC-004 Applicability related to generators. It would indicate that

Organization	Yes or No	Question 9 Comment
		all protection systems at a generating plant that is part of the BES would be included. Is that the intent or is it only the Protection Systems associated with the protection of the Generator and/or step-up bank? 3) We suggest separating the Guideline and Technical Basis document from the remainder of the standard so that the document is less overbearing. â€,â€, 4) As stated in the responses to several earlier questions, we recommend combining R2 with R1 and making the deadline for each the date of reporting to the RE, eliminating R3, renumbering R4 to R2, adding the revised version of Attachment 1 to the standard, and adding a new requirement which specifies the reporting responsibilities that are contained in the Compliance section C1.4. Based on our experience as a large utility in investigating, tracking, and reporting relay operations and misoperations, we believe these changes will be simpler, more efficient, more cost effective to implement while still achieving the desired goals.

Response: Thank you for your comments.

(1) The drafting team believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.

(2) Protection Systems that protect Facilities that are part of the BES and respond to electrical quantities such as overcurrent, loss of excitation, generator differential, step-up transformer differential and so forth. Trips such as turbine trips, fuel system trips, or boiler trips are not covered.

(3) The "Guidelines and Technical Basis" is reference information.

(4) The drafting team appreciates your suggestions and realizes there are other ways of structuring the standard; however, the posted version was developed and modified based on stakeholder comments. The drafting team declines to make the changes regarding the requirements. The reporting obligations have been removed from the standard. Please see the drafting team's decision surrounding 'reporting' in the Summary Consideration for Question 5 on Page 141 of this document.

Organization	Yes or No	Question 9 Comment
City of Jacksonville Beach, FL dba/ Beaches Energy Services		1) Applicability of 4.2.1 “Protection Systems for Facilities that are part of the BES” is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. We recommend using the FERC approved interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted.
Response: Thank you for your comments. **(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase ‘transmission Protection System.’ The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: ‘…a BES interrupting device operation in its Facility caused by a Protection System operation…’ The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.** **(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.** **(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…** **(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
Florida Municipal Power Agency		1) Applicability of 4.2.1 “Protection Systems for Facilities that are part of the BES” is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. FMAP recommends using the FERC approved

Organization	Yes or No	Question 9 Comment
		interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted.
Response: Thank you for your comments. **(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase 'transmission Protection System.' The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: '…a BES interrupting device operation in its Facility caused by a Protection System operation…' The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.** **(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.** **(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…** **(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
Tampa Electric Company		1) Applicability of 4.2.1 "Protection Systems for Facilities that are part of the BES" is not consistent with the interpretation of PRC-004-1 Attachment 1 nor the applicability of PRC-005-2. TEC recommends using the FERC approved interpretation of PRC-004-1 Attachment 1. 2) R3 is not needed, is administrative in nature, and provides no reliability benefit. 3) R2 should be modified to be applicable only to misoperations where cause(s) were

Organization	Yes or No	Question 9 Comment
		identified. 4) R4.2 is administrative in nature, is a Measure, not a requirement, and should be deleted. 5) The big change that I see for us is significantly increased documentation. Currently all of our documentation is in a database including a brief description of the corrective action plan. It seems to satisfy the new standard we would need a separate CAP document to capture all of the additional info they are asking for, we may be able to link the CAP document to our database. The standard asks for documented proof that the work associated with the CAP was actually done (data from work management system, work order etc.). Presently we just log the completion date in our database we don't capture any proof that the work was done. Fortunately we typically only have a few misoperations per year so the volume of work will not be huge but it is just another ratcheting up of the documentation requirements. TEC doesn't see the increased documentation requirements doing anything to increase our reliability.

Response: Thank you for your comments.

(1) The drafting team believes there is no conflict between PRC-004-3 and the interpretation of the phrase 'transmission Protection System.' The Applicability Section of PRC-004-3 includes: Protection Systems for Facilities that are part of the BES, and Requirement R1 stipulates: '…a BES interrupting device operation in its Facility caused by a Protection System operation…' The drafting team believes these are consistent with the interpretation. The drafting team also believes there is appropriate consistency between PRC-004-3 and PRC-005-2. The Protection Systems that are described in the 4.2 Facilities section of PRC-005-2 but are not covered in the PRC-004-3 Facilities description are excluded because either there is a plan to include them in the next phase of this project, they are already addressed by another standard, or they are automation and control functions that are not protection specific.

(2) The drafting team believes Requirement R3 is essential because it provides a path to resolution if a Misoperation is identified but no cause is determined within the first 120 days.

(3) Requirement R2 states: Within 60 calendar days of identifying the cause of each Misoperation…

Organization	Yes or No	Question 9 Comment
(4) The drafting team agrees and revised Requirement R4 to eliminate the Parts. **(5) The drafting team modified Measure M4 to read: '…The evidence <u>may</u> also include dated work management program records, dated work orders, or dated maintenance records.'**		
Orange and Rockland Utilities		As a result of the new BES Definition (100 kV Bright-line), some new BES assets could be identified. The timeline proposed in R1, R2, and R3 in this Standard should not apply to the newly identified BES assets.
Response: Thank you for your comment. **The Implementation plan for the definition of BES states: Compliance obligations for Elements included by the definition shall begin 24 months after the applicable effective date of the definition. The drafting team believes that the 24 months allowed with the BES definition provides ample time to implement all of the requirements of PRC-004-3.**		
ITC		1) Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the first or second half of the year. This comment was provided in July 2011, but the response did not explain the reason for quarterly reports. If the SDT feels it should remain, than please provide a technical justification for this decision. 2) Has the "Application Guidelines" been thoroughly reviewed? Why haven't there been any questions regarding what is in these guidelines? None of the Requirements, Measures or Compliance sections mentions it, so it should be treated only as a reference-guide. 3) R2, first bullet point requires an entity to analyze the applicability of a CAP to other protection systems. This should be removed as it exceeds the scope of this standard.
Response: Thank you for your comment. **1) The drafting team has removed all reporting obligations from the draft standard.**		

Organization	Yes or No	Question 9 Comment
2) Application Guidelines are included as part of the NERC "Results Based Standard" format. They contain no requirements or measures, and are intended to be a reference. **3) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.**		
Souhwest Power Pool Reliability Standards Development Team		1) Can Attachment 1 be tabbed format or something easier to use than the long spreadsheet provided? 2) Also we don't agree that the quarterly interval and if this is in conjunction with TADS and GADS then both of these are only reported annually. 3) In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review the system over a 24 month period, but doing this all the time seems overly burdensome. 4) Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to miss classification of misoperations. Protection System operations which occur with the protected Element out of service, that trip any in-service Elements are Misoperations. Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing,

Organization	Yes or No	Question 9 Comment
		construction or commissioning activities.
Response: Thank you for your comment. 1) **The Quarterly Protection System Misoperation Reporting Template is reviewed annually by the ERO-RAPA group and the NERC System Protection and Control Subcommittee. Attachment 1 provides field descriptions and sample data for completing the reporting template.** 2) **The drafting team has removed all reporting obligations from the draft standard.** 3) **An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.** 4) **The drafting team revised the Application Guideline to read: Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.**		
CenterPoint Energy		CenterPoint Energy recommends deleting R4.2 which states the following: "Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion." With R4.1 being a performance-based requirement to "Implement the CAP or action plan", CenterPoint Energy believes it is unnecessary to establish a requirement related to documentation needs.
Response: Thank you for your comment. **The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
MISO		Clarification should be provided of what approvals or coordination the identified responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The interaction between the Protection System owner and their system operator must be worked out between the two. It should be indicated in the CAP how operating instructions were modified to prevent a Misoperation from recurring.**		
Essential Power, LLC		Compliance section C1.4 contains a requirement to report to the RE – this needs to be in the requirement section of the standard.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		
Modesto Irrigation District		Concept of standard is generally very good. Please remember to keep overall reliability goals in mind, and not have entities (especially small ones like ours) get bogged down in paper-trail activities.
Response: Thank you for your comment. **Results Based Standards are intended to focus on what is beneficial to the reliability of the BES.**		
Manitoba Hydro		1) Effective Date - The language regarding the effective date needs to contemplate that Manitoba Hydro, like some other Canadian jurisdictions, will not have effective dates that are tied to Board of Trustees approval. We assuming that is what the proposed reference to 'laws applicable to such ERO governmental authorities' means but this is somewhat confusing. It would be more accurate to refer to the laws applicable to such functional entities. 2) Background - We are not clear on whether the 'Background' section of the proposed standard becomes part of the standard when final or if it's just included at this stage when the proposed language is being circulated. Assuming it does become part of the standard, there are several issues with this section as drafted. There needs to be some sort of introductory sentence at the beginning of the paragraph that explains that PRC-004-3 is designed to replace PRC-004-2a and PRC-003-0

Organization	Yes or No	Question 9 Comment
		because otherwise there is no context for why these two standards are being discussed. The full name of the standard should be used in the fourth line (missing the words “Identification and Correction”). The NOPR is discussed without any explanation of what it is - the full name, date published, by FERC etc is needed. The same can be said for the reference to the SAR further down the page. The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". The terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above. 3) R2 - More details should be provided regarding what level of detail is required when developing a CAP. Perhaps a template could be developed and attached to this standard. 4) Also, the wording of R2 should be made more consistent with the wording of R3. R2 implies that a cause will always be identified. We suggest the words “For each Misoperation with an identified cause(s)” be added at the beginning of R2. 5) R3 - The second bullet regarding the declaration should be re-worded to be consistent with the wording in R2. 6) C. Compliance - (i) An acronym is assigned to CEA in 1.1, but it is used in full in 1.2. This is not necessary. (ii) The term “BES Protection Systems” is used in C. Section 1.2. It would be more accurate to use the term given in 4. Applicability, Section 4.2.1 “Protection Systems for Facilities that are part of the BES”. (iii) C. Section 1.4 refers to PRC-004. It should refer to PRC-004-3. 7) Technical Guidelines - Proper and complete references to document they refer to should be provided. For example, the July 2011 Risk Assessment doesn't indicate who published this or conducted this, where it is available, etc.

Response: Thank you for your comment.

Organization	Yes or No	Question 9 Comment
1) The language used for the Effective Date description is boiler plate language used in all NERC Reliability standards. 2) The Background section is included in the final version of the approved standard. The drafting team included the full name of the standard. The drafting team removed the reference to the NOPR and replaced it with FERC Order No. 693. 3) The drafting team believes the Protection System owner should be allowed the freedom to draft each CAP based on the aspects of each Misoperation. 4) The Requirement R2 wording directs the Protection System owner to develop a CAP if a Misoperation cause is identified. The drafting team declines to make the suggested change. 5) The declaration from Requirement R2 applies when a cause has been identified but there are specific reasons why corrective actions cannot or should not be performed. The declaration from the second bullet of Requirement R3 applies when a cause has been not identified and there are specific reasons why the investigation is going to be terminated. Consistent wording would blur the distinction between them. 6) The drafting team made the suggested changes other than the BES Protection System recommendation. 7) The drafting team has added a link to the referenced document in a footnote.		
Entergy Services, Inc. (Transmission)		Entergy is concerned with the lack of definition surrounding the statement "review each Protection System operation" in R1.
Response: Thank you for your comment. The level of scrutiny required to designate if an operation of a Protection System was proper or not is left to the Protection System owner to determine. Each entity must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information.		
El Paso Electric		EPE believes additional clarity under the “Additional Compliance” section would be helpful as it relates to reporting misoperation data. EPE believes the insertion of some additional language may provide clarity, such as “.....shall submit data identified on Attachment 1 for misoperations identified within a quarter...”

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The drafting team declines to make the suggested change.**		
Portland General Electric Company		1) 4.2.2 excludes UVLS from this standard due to the existence of PRC-022, but it is expected that PRC-022 will be superseded much like its UF counterpart PRC-009. Rather than requiring a revision of PRC-004, 4.2.2 should be worded such that UVLS schemes would be covered by PRC-004-3 at such time as PRC-022 is retired. 2) Additional resources and signification database modifications will be required to ensure proper documentation of compliance.
Response: Thank you for your comment. **1) The drafting team must work within the constraints of the project's SAR.** **2) The drafting team believes the proposed level of documentation is appropriate.**		
Clark Public Utilities		I am confused on the requirement to provide a quarterly report. In the current draft the reference to this requirement appears in Section 1.4 of the Compliance Monitoring Process. This requirement does not appear to be in the Requirements and Measures section. The quarterly reporting also does not appear to be in the Violation Severity Levels. So it appears that in this draft, there is no real "Requirement" that a quarterly report be submitted and there is no assignment of a violation to those TOs, GOs, and DPs that do not submit a quarterly report. Is that so or am I missing something? This seems odd. If TOs, GOs, and DPs are supposed to submit a quarterly report, why isn't this included in the Requirements? Please eliminate this ambiguity. Either add the reporting to a Requirements provision or get rid of the reference to the reporting requirement in the Compliance Monitoring section.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		

Organization	Yes or No	Question 9 Comment
Cleco Corporation		1) In R2 under the first bullet the way it reads it would seem that you have to look at your entire system for a single misoperation. In example if you had the wrong setting on a single 421 do you have to go and look at every 421 on your system. This seems overly burdensome and could lead to someone constantly looking at the system. If you had a certain relay failure at one location do you go to all other locations that have that relay? If so then would you have to prove that at other locations you don't have this particular relay? The team may want to look at rewording this bullet maybe taking a sample of equipment or adding an additional bullet and gather all the CAPS for the year and review the system over a 24 month period, but doing this all the time seems overly burdensome. 2) Under the Application Guidelines generator protection section it has some language that is conflicting with section 6 of the proposed definition. We would suggest that the reference in the guidelines be removed. This could cause confusion with the industry and lead to miss classification of misoperations.
Response: Thank you for your comment. **1) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.** **2) The drafting team revised the Application Guideline to read: Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.**		
Wisconsin Electric		In the Applicability section, in 4.2.3 relay functions not included, under 4.2.3.1 Control: add "Generator Excitation controls/limiters and turbine controls" to the existing exclusions list. The revised wording suggested is: "4.2.3.1 Control (e.g. controlled shutdown of generators, generator excitation controls/limiters, turbine controls, capacitor or reactor bank switching".

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. **The drafting team revised the Applicability Section 4.2.4 to read: Non-protective functions that may be imbedded within a Protection System are not included (see Guidelines and Technical Basis section for detailed examples).**		
City of Austin dba Austin Energy		In the Applicability text box, the following phrase “of the automation portion” should likely be “or the automation portion.”
Response: Thank you for your comment. **The drafting team corrected the typographical error.**		
Indiana Municipal Power Agency		1) In the Application Guidelines, page 18 of 22, the following statement is made: "The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records." By making this statement in the Application Guidelines, it seems to be requiring entities to have sequence of events AND Disturbance Monitoring Equipment records. IMPA believes that this is not the intent of the SDT and recommends using the words "may contain the sequence of events, relay targets,... 2) "In addition, IMPA agrees with the comments that Florida Municipal Power Agency submitted for this question.
Response: Thank you for your comment. **1) The standard does not require any additional monitoring equipment to be installed. Each TO or GO must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT. The drafting team modified the sentence in the Application Guidelines to address your concern. The Application Guidelines are reference information only and are not mandatory and enforceable.** **2) Please see the drafting team’s response to Florida Municipal Power Agency.**		

Organization	Yes or No	Question 9 Comment
US Bureau of Reclamation		Including the TADS information provided under the NERC Rules of Procedure is in conflict with this standard. TADS' reporting is on an annual basis. By including the TADS event ID, the standard would require quarterly reporting of the TADs event. The inclusion introduces the conflict between the rules of procedure and a standard. Including the quarterly reporting as part of the compliance information is not consistent with standard requirements. There is requirement VRF or VSL assigned to the reporting and therefore no compliance violation can be assessed for failure to respond. The reporting information is not subject to a requirement per Commission guidance since it is only for metrics and administrative purposes per the SDT. The information collected under this standard is inconsistent with the information collected for Transmission system events. TADs event data is collected under the NERC Rules of Procedures. The standard should be modified to remove the reference to the additional compliance information and have the information collected under the NERC Rules of Procedures.
Response: Thank you for your comment. **The drafting team has removed all reporting obligations from the draft standard.**		
Nebraska Public Power District		1) It sounds like a CAP is a case by case document for each misoperation and does not need to be a formal CAP process document that explains the steps that will be followed for all misoperation investigations. Is this correct? 2) I have concerns with the open ended nature of the statement in R2 "Develop and document a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations". Specifically my concerns are with the last part referring to "at other locations". I am curious how the STD would consider if a miscoordination resulting in a misoperation were to happen on their system. Would they consider reviewing the coordination for every relay at every substation on their system? This requirement has value yet also opens the door to unreasonable CAPs as

Organization	Yes or No	Question 9 Comment
		well. This requirement also seems quite subjective in how it could be audited as well. Does the STD share this concern? 3) Will the registration criteria or BES definition be referenced to set generation sizes for reporting misoperations? The application guidelines are very helpful in explaining the SDT expectations and should continue to be part of the standard for guidance.
Response: Thank you for your comment. **1) The drafting team concurs. As defined in the NERC Glossary of Terms, a Corrective Action Plan (CAP) is defined as: A list of actions and an associated timetable for implementation to remedy a specific problem.** **2) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.** **3) The Applicability Section, 4.2 Facilities 4.2.1 states: Protection Systems for BES Elements. The Application Guidelines are a permanent part of the standard.**		
Luminant		Luminant does not agree with Requirement R3 of the standard since there is an apparent conflict or double jeopardy with the draft standard on generator relay loadability (PRC-025-1). Luminant recommends that R3 of PRC-025-2 be removed and any event from a generator load responsive relay for review be in the draft PRC-004 standard that operates an interrupting device. The chairmen of both SDT's should consult with one another to remove any conflicts.
Response: Thank you for your comment. **This issue has been addressed by the PRC-025-1 drafting team.**		
Northeast Power Coordinating Council		1) Measurement M1 has that "Acceptable evidence for Part 1.3 may include, but is not limited to, a copy of dated investigation report or documented findings for each Misoperation." This provides a choice in a document type with either

Organization	Yes or No	Question 9 Comment
		a formal report or other method of documenting the findings. On page 22 of 28 of PRC-004-3, in the Application Guidelines section, it states "An investigation report may include...” which dictates the use of an investigation report, and eliminates the choice between a formal report or other method of documenting findings as stated in M1. The Application Guidelines should be consistent with the standard portion of the document. 2) There is a typographical error on the first bulleted item on page 6 of the standard. This item should read: Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).
Response: Thank you for your comments. **1) The drafting team revised the Application Guideline to address your concern.** **2) The drafting team corrected the text.**		
NextEra Energy Inc.		1) NextEra encourages the Standards Drafting Team to improve the wording used in R2. At this time, the wording appears to apply to all situations without qualification and does not consider several situations that may be relevant. To clarify the language, NextEra recommends the following changes to R2. ”R2. Within 60 calendar days of identifying the cause(s) of each Misoperation pursuant to R1.3, the Transmission Owner, Generator Owner, or Distribution Provider shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] o Draft a Corrective Action Plan (CAP) for the identified Protection System component(s), including, if applicable, the following: (i) An evaluation of the CAP’s applicability to the entity’s other Protection Systems (ii) An explanation of why corrective actions are either: (i) Beyond the entity’s control; (ii) Cost prohibitive/significantly impacted by cost considerations;

Organization	Yes or No	Question 9 Comment
		(iii) Not to be implemented for over 5 years (iv) Would reduce BES reliability." 2) Similar to the re-write of R2, NextEra does not see the need for a "declaration" in R3. Thus, NextEra recommends that the second bullet in R3 be redrafted to read:" o An explanation of why no further actions will be taken." 3) NextEra opposes the use of "detailed" in R4.2 as unnecessary, subjective and onerous. PRC-004-3 should not be written so that an entity can be found in violation because of subjective judgments on what is or what is not detailed. 4) Further, NextEra finds that the clarity of R4.2 may be improved. Thus, NextEra recommends that R4.2 be redrafted as follows:" 4.2 Maintain implementation records for each CAP and action plan, including the dates of any revision(s) and completion." 5) Lastly, for clarity, NextEra also believes there should be linkage between R2 and R4 on the issue of applicability to other Protection Systems at other locations, and, thus, suggests the following changes to R4.1. "4.1 Implement the CAP or action plan, including, as applicable, the entity's Protection Systems at other locations that were identified in R2."

Response: Thank you for your comments.

1) **The drafting team declines to make the suggested changes.**

2) **The drafting team declines to make the suggested changes.**

3) **The drafting team revised Requirement R4 to eliminate the Parts.**

4) **The drafting team revised Requirement R4 to eliminate the Parts.**

Organization	Yes or No	Question 9 Comment
5) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.		
Detroit Edison		Overall, the draft standard is good and we already comply with most of the requirements as a general practice. The concern is around ability to properly analyze and determine iof operations, specifically around generation, would be considered slow. As of today, there is not adequate monitoring (and many of the conditions are far too dynamic to properly determine what the proper operating time should have been) to determine how quickly a relay responded to a "other than fault" condition. Would recommend a "yes" vote if there was wording stating that it is not a misoperation if the data that exists is not of a fine enough resolution to prove a relay was slow.
Response: Thank you for your comments. **The standard does not require any additional monitoring equipment to be installed. Each TO or GO must review each of its Protection System operations and determine whether the operation should be categorized as a Misoperation based on its available information. The entity will use whatever means at their disposal in order to determine whether the operation was correct or not which may include available DISTURBANCE MONITORING EQUIPMENT.**		
Associated Electric Cooperative Inc - JRO00088		Page 6, Line 1,Replace: "Analyze Misoperations Protection Systems"With: "Analyze Misoperations of Protection Systems" Rationale: Grammar and alignment with phrase from preceding bullet
Response: Thank you for your comments. **The drafting team corrected the text.**		
Dairyland Power Cooperative		1) R2 and R3 the second bullet is administrative and redundant, and does not aid in the protection of the BES. Recommend removing the second bullet from R2 and R3. This is captured within the first bulleted item.

Organization	Yes or No	Question 9 Comment
		2) R4.2 is administrative and does not aid on the protection the BES. Recommend removing R4.2
Response: Thank you for your comments. **1) The drafting team declines to make the suggested changes. A declaration provides a means of closing unresolved Misoperations where corrective actions are beyond the entity's control or would reduce BES reliability, or where no further actions can be taken.** **2) The drafting team agrees and revised Requirement R4 to eliminate the Parts.**		
The United Illuminating Company		1) R2 should not specify that the CAP contains an activity to evaluate applicability to all of the entity's Protection System. It could create a situation where check-sheets are required with sign-offs for review of all systems. 2) R4.2 is of concern with the requirement to maintain detail implementation records of each CAP or action plan. Detail is an ambiguous word that cannot be complied to. The compliance burden to provide detailed implementation records is excessive. A Transmission Owner is audited every 6 years. A TO will need to provide detailed records of CAP's and action plans for 6 years. The only organization receiving a benefit from this requirement is the NERC Audit team. All that should be required by the Standard is the date of completion on the CAP implementation. 3) Additionally, There should be no requirement to record revisions to the CAP.
Response: Thank you for your comments. **1) An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.** **2) The drafting team revised Requirement R4 to eliminate the Parts.** **3) The drafting team revised Requirement R4 to eliminate the Parts.**		

Organization	Yes or No	Question 9 Comment
Public Service Company of New Mexico		R3 as drafted could be difficult to audit. PNMR suggests additional clarity be provided around what would be an acceptable criteria to invoke “A declaration explaining why no further actions will be taken.” As the standard is written now it appears that an RE could just declare a misop as having an unquantifiable cause and then declare that no further action is warranted or will be taken.
Response: Thank you for your comments. **Measure M3 states the entity must have evidence that includes a dated action plan or a dated declaration. A "no action plan” declaration would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.**		
ReliabilityFirst		ReliabilityFirst Abstains and offers the following additional comments for consideration: 1) ReliabilityFirst believes there are extra and unneeded deadlines in the standard that do not provide a reliability benefit. 2) ReliabilityFirst believes there is a potential for late identification of Misoperations which will result in violations even if they are not particularly significant to grid reliability. For example, capacitor bank trips occur every day as part of normal switching. It may not be obvious if it was by a Protection System Misoperation, particularly if a relay is used for multiple purposes like ON/OFF switching control and protection. 3) ReliabilityFirst has a concern that there is no maximum time to complete CAPs listed in the draft standard. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause should be either mitigated or the CAP completed in something like 6 - 12 month time period.
Response: Thank you for your comments. **1) The reliability of the system relies on prompt discovery, investigation and mitigation of any Misoperation to avoid**		

Organization	Yes or No	Question 9 Comment
reoccurrence or occurrence in other Protection Systems. 2) The drafting team believes 120 days is an adequate amount of time to review Protection System operations and identify any Misoperations. 3) Establishing fixed time limits for the conclusion of CAP is impractical because of the wide spectrum of Misoperation causes and the variety of corrective actions. A schedule or timetable is required to be included in the CAP.		
Bonneville Power Administration		Section 4.2 is titled Facilities. The NERC definition of facility is a set of electrical equipment that operates as a single BES element. The NERC definition of element is any electrical device with terminals that may be connected to other electrical devices, such as a generator, transformer, circuit breaker, bus section, or transmission line. Based on these definitions, it would seem that a protection system is not an element or a facility. 1) BPA suggests renaming Section 4.2 to "Equipment" or "Systems". 2) Section 4.2.2 should be renamed from "Facilities not included" to "Protection Systems not included" or something similar. 3) The last paragraph of Section A.5, Background notes that PRC-004-WECC-1 overlaps with this standard and says that entities are expected to comply with the more stringent standard. Rather than leave it up to the entity to determine which of the standards is more stringent, BPA suggests simply stating which of the standards takes precedence and which can be ignored.
Response: Thank you for your comments. 1) Section 4.2 Facilities is a part of the NERC results based standard template. It is beyond the scope of the drafting team to modify the template. 2) The drafting team revised Section 4.2.3 (the former 4.2.2) to eliminate the term 'Facilities' by incorporating the subsections into the 4.2.3. 3) Regional standards are required to be more stringent than the continent-wide NERC Reliability Standards. Entities are required to comply with both the continent-wide NERC Reliability Standards and any Regional standards issued by their		

Organization	Yes or No	Question 9 Comment
Region.		
Sacramento Municipal Utility District		SMUD agrees with the concepts for addressing misoperations presented in this draft PRC-004 standard. We do have concerns with the 'zero-defect' approach and urge the Standard Drafting Team to embrace the integration of Internal Controls into this reliability standard to help the entity achieve the standard's reliability objectives. This would better align the standard with ongoing activities such as the FFTR, Paragraph 81 and other tasks underway. We thank you for considering all of our comments in Questions 1 - 9 on this standard.
Response: Thank you for your supportive comments. **The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
American Electric Power		1) The following excerpts from the "Consideration of Comments" document should be added to item "(3)" of the "Guidelines and Technical Basis" section to clarify the intent of the "Slow Trip" category: "In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection for meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported. However, even if high speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). 2) "Facilities 4.2 - Should the text "Also see Guidelines and Technical Basis section for detailed examples" be taken out of 4.2.3.1 and applied more broadly to the standard? 3) In the first bullet of R2, may an evaluation of the CAP's applicability to the entity's Protection System at other locations result in no additional actions being taken? 4) Is the "evaluation of the CAP's applicability to the entity's Protection System at other locations" part of the quarterly reporting?

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1) The drafting team revised the Application Guideline as suggested.** **2) The drafting team revised the Facilities Section 4.2 and eliminated 4.2.3.1. The Application Guidelines do expound on the non-protective functions of relays excluded from the standard.** **3) Yes. It is left to the entity to determine the range and impact of the problem. An evaluation of the CAP's applicability at other locations is intended to encourage diligence to prevent the same root cause from creating another Misoperation and having an adverse effect on reliability. It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP.** **4) The drafting team has removed all reporting obligations from the draft standard.**		
Consumers Energy		The quarterly reporting of Misoperations provides no benefit to the reliability of the Bulk Electric System and the entities are required to spend additional resources to develop these quarterly reports instead of focusing on the actual reliable operation of the BES. Performance metrics can be determined on a yearly basis, through annual reporting.
Response: Thank you for your comments. **The drafting team has removed all reporting obligations from the draft standard.**		
ISO/RTO Standards Review Committee		The SRC seeks clarification of what approvals or coordination the identified responsible entities need to undertake if a Corrective Action Plan (CAP) includes some operational solutions provided by a system operator.
Response: Thank you for your comment. **The interaction between the Protection System owner and their system operator must be worked out between the two. It should be indicated in the CAP how operating instructions were modified to prevent a Misoperation from recurring.**		
Tacoma Power		1) Under Applicability (comment box to side), change 'RMS' to 'RAS.'

Organization	Yes or No	Question 9 Comment
		2) Why does "(e.g., data collection)" need to be included under 4.2.3.2? Data collection does not operate anything. 3) Referring to the second bullet of page 5 (red-line version), change "...Misoperations Protection..." to "...Misoperations of Protection..."
Response: Thank you for your comments. **1) The drafting team made the correction.** **2) The drafting team revised the Facilities Section of the standard and eliminated 4.2.3.2.** **3) The drafting team made the correction.**		
Western Area Power Administration		We agree that these are good business practices and, in fact, we are currently performing these practices already. 1) However, we have a great deal of concern that the documentation burden required to meet compliance continues to increase exponentially. We would like to point out that the current documentation requirements are diverting a significant portion of our resources away from system improvements. 2) Please add the following items (found in the Applications Guidelines) directly into the standard requirements: a) Delayed fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required by planning studies associated with the TPL standards or by coordination requirements with other Protection Systems. b) An unintended operation as a result of on-site maintenance, testing, construction or commissioning is not a Misoperation. c) In some cases, where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. d) Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection

Organization	Yes or No	Question 9 Comment
		Systems.
Response: Thank you for your comments. **1) The requirements and associated documentation ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.** **2a & b) These statements are included in the definition of Misoperation.** **2c &d) The drafting team believes these statements belong in the Application Guidelines rather than the requirements and declines to make the suggested changes.**		
JEA		We believe this would be a good candidate for the new cost benefit approach. Also we believe that this is the wrong approach. NERC should focus on fixing the problem (PRC003 not being approved) by working on PRC003 instead of changing PRC004 to address deficiencies caused by lack of an approved PRC003 standard.
Response: Thank you for your comments. **The drafting team disagrees and believes this approach is the best way to address the investigations of Misoperations uniformly. Furthermore, the drafting team is bound by the scope of the SAR associated with this project and does not have the latitude to follow your suggestion.**		
PSEG		We have provided new language below that continues after our R4 above. R5 addresses implementation of the CAP or action plan. R6 requires reporting of data in Attachment 1. We believe that providing the data in Attachment 1 should be a requirement instead of being addressed in the "Additional Compliance Information" section. 1) R5. For each CAP or action plan, the Transmission Owner, Generator Owner, and Distribution Provider shall implement the CAP or action plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning] M5. Each Transmission Owner, Generator Owner, and

Organization	Yes or No	Question 9 Comment
		Distribution Provider shall have evidence for Requirement R5 that includes dated records which document the implementation of each CAP and action plan, such as work orders or maintenance records that document the completion of work or maintenance, including documentation of revisions for each CAP or action plan. 2) R6. Each Transmission Owner, Generator Owner, or Distribution Provider shall submit PRC-004 - Attachment 1 to its Regional Entity within two calendar months following the end of each calendar quarter. [Violation Risk Factor: Low] [Time Horizon: Operations Planning, Long-Term Planning] M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R6 that it transmitted PRC-004-3 - Attachment 1 to its Regional Entities within two calendar months following the end of each calendar quarter. 3) We have also addressed the “Facilities” portion of the standard in the “Applicability” section and suggest the language below, parts of which were taken from PRC-005-2. The Protection Systems in 4.2.1 and 4.2.2 provide protective functions. Section 4.2.3.3 excludes UFLS systems whose operation is evaluated in PRC-009-0. While it is clear that the team wanted to exclude relays such as reveres power relays for generators, their description of these as providing “non-protective functions” is inaccurate since they prevent a generator from motoring during shutdown. They protect the generator. We have excluded those applications in our Section 4.2.3.4 because the operation of an interrupting device caused by a reverse power relay is associated with a normal generator shutdown. The Misoperation of such a relay results in the motoring of a generator, and while that can create a serious problem for a Generator Owner who is incented to evaluate such Misoperations absent a standard, it does not create a BES reliability issue. 4.2. Facilities 4.2.1 Protection Systems that are installed for the purpose of

Organization	Yes or No	Question 9 Comment
		detecting Faults on BES Elements (lines, buses, transformers, etc.) or abnormal conditions. 4.2.2 Protection Systems for generator Facilities that are part of the BES for the purpose of detecting faults or abnormal conditions, including: 4.2.2.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. 4.2.2.2 Protection Systems for generator step-up transformers for generators that are part of the BES. 4.2.2.3 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). 4.2.2.4 Protection Systems 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. 4.2.3 Facilities not included 4.2.3.1 Special Protection Systems (SPS) or Remedial Action Schemes (RAS) 4.2.3.2 Undervoltage load shedding (UVLS) systems 4.2.3.3 Underfrequency load shedding (UFLS) systems 4.2.3.4 Relays that operate for the normal shutdown of an Element. 4) Finally, we believe in the Application Guideline, the third sentence in the first paragrgaph on p. 18 of 22 is written too restrictley. We suggest this language instead: The initial evidence, which may also be documented separately, MAY CONTAIN [delete “contains.”] the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records, TO THE EXTENT AVAILABLE.
Response: Thank you for your comments.		

Organization	Yes or No	Question 9 Comment
1) The drafting team revised Requirement R4 and it is similar to your suggested Requirement R5. 2) The drafting team has removed all reporting obligations from the draft standard. 3) The drafting team revised the Facilities Section 4.2 but declined your suggestions. 4) The drafting team revised the text to read '…contains the sequence of events, relay targets and a summary and Disturbance Monitoring Equipment (DME) records as appropriate.'		
Colorado Springs Utilities		We understand that this was an arduous standard to develop, and it required extensive explanations for requirements and measurements. We agree with the concepts presented in PRC-004-3, and we believe it was very well-written. We appreciate the effort that went into developing and reviewing this revision. However, frequent revisions of standards, coupled with frequent revisions of definitions, do not help to maintain consistent procedures for ensuring the reliability of our protection systems. We suggest that national standards only require what is deemed absolutely necessary on a national level. Any further requirements and recommendations should be provided by Regional Entities. This will mitigate misinterpretations of the standard and lessen the amount of revisions to the standard.
Response: Thank you for your comments.		
Seattle City Light		While Seattle City Light generally agrees with the concepts presented in the draft Standard and appreiates the effort required to develop and review Standards, SCL finds the reliability improvements promised by the draft to be diluted with unnecessary backwards-looking compliance activities. 1) The draft appears tone-deaf to the changes at NERC regarding purely administrative tasks (e.g., Paragraph 81 effort to remove them, whereas this draft adds several such as R4.2 and the second bullets of R2 and R3). One example is the emphasis on meeting and documenting multiple dates for each

Organization	Yes or No	Question 9 Comment
		Misoperation. Another is a need to document completion of each Misoperation CAP almost as if it were a Mitigation Plan to correct a Self-Reported violation, rather than, for example, relying primarily on the corrective action documentation already reported for GADS and TADS. 2) The draft also would benefit from application of the non-zero-defect concepts introduced with the latest draft of CIP version 5. Changes such as these will minimize the need to revise the Standard yet again to align with present directions.
Response: Thank you for your comments. **1) The requirements and associated documentation ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. Consequently, the drafting team does not believe this documentation detracts from the reliable operation of the BES.** **2) The drafting team believes the current approach meets the reliability objectives established in the SAR for this project.**		
New York Power Authority		None.
Response: Thank you.		

END OF REPORT

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. SC authorized moving the SAR forward to standard development at the June 9, 2011 meeting.
2. The SAR posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day concurrent comment and initial ballot period from July 25 – September 7, 2012.

Description of Current Draft

Draft 3 of PRC-004-3 posted for a 30-day formal comment period with parallel successive ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period with Successive Ballot	January, 2013
Recirculation ballot	February, 2013
BOT Approval	May, 2013

Effective Dates: First day of the first calendar quarter that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking

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 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault** - A failure of a Protection System to operate for a Fault within the zone it is designed to protect. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

2. **Failure to Trip - Other Than Fault** - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

3. **Slow Trip - During Fault** - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.

4. **Slow Trip - Other Than Fault** - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate.

6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.
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 for BES Elements

4.2.2 Underfrequency Load Shedding (UFLS) that trips a BES Element

4.2.3 Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded

4.2.4 Non-protective functions that may be imbedded within a Protection System are excluded

> **Applicability:** Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022-1. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion or the automation portion of relays are excluded from this standard. See the Guidelines and Technical Basis section of the standard for detailed examples of non-protective functions.

5. **Background**:

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. PRC-004-3 Protection System Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not usable to establish consistent metrics for measuring Protection System performance. As such, the drafting team is removing the data obligation from the standard and is developing a data request under Section 1600 of the NERC Rules of Procedure. NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The data submitted as part of the data request will not be used for compliance or enforcement purposes. The removal of the data collection from the standard does not result in a reduction of reliability as Responsible Entities are required to retain evidence of compliance for audit and compliance purposes under the Compliance Section C 1.2 Evidence Retention portion of the standard.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations of or associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding are not addressed in this standard due to their inherent complexities. NERC intends to address these areas through future projects.

Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.

- If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation.

Rationale for R1: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The drafting team believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.

- If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.
    - The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.

1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1 that may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date and time of each applicable interrupting device operation and indicates when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date, time, Facility and equipment name associated with each Misoperation, a copy of a dated Misoperation investigation report or documented findings, which may include sequence of events, relay targets, summary of DME records for each Misoperation.

Rationale for R2: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule for a CAP. When the cause of a Misoperation is determined from implementing an action plan in accordance with Requirement R4, a CAP must be developed in accordance with Requirement R2.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation investigation process and for future reference.

R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.

R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or
- A declaration explaining why no further actions will be taken.

Rationale for R3: Where a Misoperation cause is not determined during the initial investigation; implementing an action plan of additional investigation/monitoring may determine a cause and lead to the development of a CAP in accordance with Requirement R2. The 180 calendar day period is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

If the action plan completion does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close of the Misoperation investigation process and for future reference.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R3 that must include a dated action plan or a dated declaration.

R4. Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]*

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan and the completion of actions for each CAP or action plan. The evidence may also include dated work management program records, dated work orders, or dated maintenance records.

Rationale for R4: The CAP or action plan must be completed to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan. When the cause of a Misoperation is determined from implementing an action plan, a CAP must be developed in accordance with Requirement R2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

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.

The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Assessment, Operations Planning**	**Medium**	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 120 calendar days but less than or equal to 150 calendar days of the operation's occurrence. OR The responsible entity identified a Protection System operation that operated one of its BES interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 150 calendar days but less than or equal to 160 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 160 calendar days but less than or equal to 170 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 170 calendar days of the operation's occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1. OR

			OR The responsible entity completed its review of a Protection System operation that operated one of its BES interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.2.			The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.2. OR The entity that owns the BES interrupting device but does not own the entire Protection System could not determine if the operation was correct and failed to notify the other owner(s) of the Protection System component(s) and provide any requested investigative information in accordance with Requirement R1, Part 1.1.
R2	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days

			days but less than or equal to 70 calendar days following the identification of the cause of the Misoperation.	days but less than or equal to 80 calendar days following the identification of the cause of the Misoperation.	days but less than or equal to 90 calendar days following the identification of the cause of the Misoperation.	following the identification of the cause of the Misoperation. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.
R3	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to 210 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 210 calendar days but less than or equal to 220 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 220 calendar days but less than or equal to 230 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than 230 calendar days following the associated BES interrupting device operation. OR The responsible entity failed to develop an action plan or a declaration in accordance with Requirement R3.

R4	**Operations Planning, Long-Term Planning**	**High**	The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP or action plan in accordance with Requirement R4.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

The composite Protection System in the context of this standard is the total complement of protection for a system Element. All protection for a given Element such as primary, secondary, backup, pilot and non-pilot relay schemes are included in the composite Protection System for the Element. These individual schemes or systems may be isolated or function independently, but aggregate as part of one composite Protection System.

A Protection System is defined in the NERC Glossary of Terms as:

- 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.

Circuit breaker and other interrupting device mechanisms are not part of a Protection System.

A revised Misoperation definition is being proposed for industry adoption; the failure of an Element's composite Protection System to operate as intended. The definition includes the following categories:

(1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

A failure of a transformer's composite Protection System to operate for a transformer Fault is an example of a "failure to trip" Misoperation. This type of Misoperation typically results in the Fault being cleared by remote backup Protection System operations.

A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "failure to trip" Misoperation as long as another component of the transformer's composite Protection System operated to clear the Fault. Please see category 3 to see if the "slow trip" classification applies to the operation.

A lack of target information, e.g. when a high-speed pilot system does not target because a high-speed zone element trips first, does not by itself constitute a Misoperation.

(2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System

component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

A failure of a generator's composite Protection System to operate for a loss of field condition is an example of a "failure to trip" Misoperation. This type of Misoperation may require manual operator intervention.

A failure of a "primary" reverse power relay (or any other component) is not a "failure to trip" Misoperation as long as another component of the generator's composite Protection System operated to shut down the generator. Please see category 4 to see if the “slow trip” classification applies to the operation.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(3) A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.

A failure of a line's composite Protection System to operate as quickly as intended for a line Fault is an example of a "slow trip" Misoperation. This type of Misoperation typically results in remote backup Protection System operations before the Fault is cleared.

In many cases, high-speed protection is installed as part of the utility’s standard practice without having the need for high-speed protection for meeting TPL requirements. A slow trip of this Protection System would not negatively impact the dynamic performance of the BES; so, it does not need to be reported. However, even if high-speed clearing is not required, the Protection Systems must coordinate to prevent an “unnecessary trip” Misoperation (e.g. an over trip).

The phrase “slower than intended” means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate.

The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.

Coordination with other Protection Systems refers to the need to ensure that relaying operates in the proper or planned sequence (i.e. the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

(4) A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate.

A failure of a generator's composite Protection System to operate as quickly as intended for an over excitation condition is an example of a "slow trip" Misoperation. This type of Misoperation may result in equipment damage.

The phrase “slower than intended” means the composite Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(5) A Protection System operation for a Fault for which the Protection System is not intended to operate.

An operation of a transformer's composite Protection System which over trips for a properly cleared line Fault is an example of an "unnecessary trip" Misoperation. For this type of Misoperation, the Fault is typically cleared properly by the faulted equipment's composite Protection System (line relaying, in this case) without the need for an external Protection System’s operation.

An operation of a properly coordinated remote Protection Systems is not a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the local Protection System to clear the Fault. An interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

(6) A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Non-Fault conditions include but are not limited to power swings, over excitation, loss of excitation, frequency excursions and normal conditions.

An operation of a line's composite Protection System due to a relay failure during normal conditions is an example of an "unnecessary trip other than Fault" Misoperation.

In a second example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation. In a third example, an impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because it was set with an excessive reach that unnecessarily restricted the line's load carrying capability.

An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspection, construction or commissioning is not a Misoperation. However, once the maintenance, testing, inspection, construction or commissioning has been completed, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of the technical personnel.

This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.

The exclusion of a component failure, as long as the composite Protection System operates correctly, was based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. Covering these types of component failures within the standard constitutes additional administrative burden for types of failures that have no immediate reliability impacts.

Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard. Automation (e.g. data collection) is also not a protective function and is not subject to this standard.

A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation provided no in-service BES Elements are tripped. These types of operations are excluded when the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not Misoperations. Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.

In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying.

In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.

This standard addresses the reliability issues identified in the letter[1] from Gerry Cauley, NERC President and CEO, dated January 7, 2011. "Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events…….. Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations." The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[2]; July 2011 "….a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.

Requirement R1

This requirement promotes the prudent evaluation of each Protection System operation to determine if the operation was correct or a Misoperation, even those Misoperations difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed operations resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the BES interrupting device owner does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. In this case, it is expected that both entities will work together to investigate the cause of the operation.

[1] http://www.nerc.com/news_pr.php?npr=723
[2] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

Protection Systems are made of many components. These components may be owned by more than one entity. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation.

Determining the cause of Protection System Misoperations is essential in developing an effective remedy to avoid future Misoperations. The drafting team recognizes that there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. The drafting team believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in a Misoperation investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.

Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a single Protection System causes multiple BES interrupting device owners to be affected, the entities may work together to produce a common Misoperation investigation report. Similarly, if the BES interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report.

A Misoperation investigation report or documented findings may include the following information: 1) initial evidence, 2) probable causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records as appropriate. Probable causes are those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the cause. The conclusions should summarize the cause(s) substantiated by the evidence and findings of the tests and studies.

Requirement R2

If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. The drafting team recognizes there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. Based on industry experience and operational coordination timeframes, the drafting team believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule for a CAP, or to prepare a declaration justifying the lack of a CAP.

The 120 day time period and the 60 day time period are distinct and within the context of Requirement R1 and Requirement R2 respectively, need to remain separate. With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days. Also, if the interrupting device owner is tardy in informing another Protection System component owner and using up much of the 120 day period, it still leaves a considerable amount of time (at least 60 days) to develop an action plan for further investigation by the Protection System component owner, or if a cause is determined the creation of the CAP.

Where there are multiple Protection System owners involved in a Misoperation, the one or more owners whose Protection System component(s) contributed to the Misoperation will create a CAP or declaration as required by Requirement R2. Owners whose Protection System components operated correctly do not need to create a CAP.

Resolving Misoperations benefits the Protection System owner and the BES by maintaining reliability and security. The CAP is an established tool for resolving operational problems. The NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".

Protection System owners are expected to exercise due diligence in the development and implementation of a CAP. Typically included would be any corrective actions taken to prevent recurrence (along with the date performed), any corrective actions planned to be taken to prevent recurrence (along with the planned date), and an evaluation of the CAP's applicability to other Protection Systems owned by the entity.

The evaluation of the CAP’s applicability to other Protection Systems owned by the entity is intended to encourage diligence in preventing similar Misoperations. The Protection System owner is responsible for determining the scope of the problem, and for including appropriate actions in the CAP. The evaluation may result in adding preemptive actions to the CAP. The CAP is complete when all specified actions are completed.

<u>The following are examples of Corrective Action Plans (CAPs):</u>

CAP Example 1 – Corrective actions for a failed relay only:

> The impedance relay was removed from service on 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance

relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 6/5/12.

Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred only occasionally within our system. This type of impedance relay is gradually being replaced with microprocessor relays as Protection Systems are modernized. It is therefore our assessment that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for our system.

CAP Example 2 - Corrective actions for a failed relay, and a program for preemptive actions at similar installations:

The impedance relay was removed from service on 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 6/5/12.

Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that a program should be established by 12/1/12 for wholesale preemptive replacement of capacitors in this type of impedance relay.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/12.

CAP Example 3 - Corrective actions for a failed relay; and preemptive actions for similar installations:

The impedance relay was removed from service on 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 6/5/12.

Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that preemptive replacement of capacitors in this type of impedance relay should be pursued.

It is planned to replace the impedance relay capacitors at stations A, B, and C by 9/1/12. It is planned to replace the impedance relay capacitors at stations D, E, and F by 11/1/12. It is planned to replace the impedance relay capacitors at stations G, H, and I by 2/1/13.

The impedance relay capacitor replacement was completed at stations A, B, and C on 8/16/12. The impedance relay capacitor replacement was completed at stations

D, E, and F on 10/26/12. The impedance relay capacitor replacement was completed at stations G, H, and I on 1/9/13.

CAP Example 4 - Corrective actions for a firmware problem; and preemptive actions for similar installations:

Fault records were provided to the manufacturer on 6/4/12. On 6/11/12, the manufacturer responded that the misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 6/12/12.

Applicability to other Protection Systems: Based on our risk assessment, we plan to install firmware version 3 at all of our installations that are determined to be version 2. Proposed completion date is 12/31/12.

The firmware replacements were completed on 12/4/12.

If the Misoperation cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners are required to make a declaration to this effect. A "no CAP declaration" would typically include the Misoperation cause and justification for taking no corrective action.

An example of a "no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is expected to be used sparingly.

There are some cases where a Misoperation cause is outside of an entity's control and would result in a "no CAP declaration." Items that may be considered outside of an entity's control could be a non-registered entity communications provider problem or a transmission transformer tapped industrial customer who initiates a direct transfer trip to a registered entity's transmission breaker. Generally, situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control. The "outside an entity's control" declaration is expected to be used sparingly.

Requirement R3

If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).

At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days are the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.

An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."

An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."

An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review by xx/xx/xx."

If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this effect. A "no action plan" declaration would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.

An example of a "no action plan" declaration might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."

Requirement R4

The goal of the standard has not been met unless CAPs or action plans are actually implemented, as is required in Requirement R4. The responsible entity is required to implement and complete a CAP or action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The responsible entity is also required to complete the CAP or action plan, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement R2. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.

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. The SAR posted for informal comment June 10, 2011 through July 11, 2011.~~

~~2.~~1. SC authorized moving the SAR forward to standard development at the June 9, 2011 meeting.

2. ~~First posting of Draft Version 1 on~~ The SAR posted for informal comment June 10 – July 11, 2011 ~~with~~.

3. Draft 1 of PRC-004-3 was posted for a 30-day comment period ~~closed on~~from June 10 – July 11, 2011.

4. Draft 2 of PRC-004-3 was posted for a 45-day concurrent comment and initial ballot period from July 25 – September 7, 2012.

Description of Current Draft

~~This is~~Draft 3 of PRC-004-3 posted for a ~~45~~ 30-day formal comment period with parallel ~~initial~~successive ballot.

Anticipated Actions	Anticipated Date
~~45~~30-day Formal Comment Period with ~~Parallel Initial~~Successive Ballot	~~July, 2012~~January, 2013
Recirculation ballot	~~October, 2012~~February, 2013
BOT Approval	~~November, 2012~~May, 2013

Effective Dates: First day of the first calendar quarter that is ~~six~~twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is ~~six~~twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking

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 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Misoperation:

~~Failure of a~~The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault** - A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~(~~The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for ~~an~~the Element it is designed to protect is correct~~.)~~.
2. **Failure to Trip - Other Than Fault** - A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~(~~The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for ~~an~~the Element it is designed to protect is correct~~.)~~.
3. **Slow Trip - During Fault** - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. ~~(~~Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance ~~is required~~has not been identified to meet the dynamic stability performance requirements of the TPL standards ~~or by~~nor is it required to ensure coordination ~~requirements~~ with other Protection Systems~~.)~~.
4. **Slow Trip** - **Other Than Fault** - A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.
5. **Unnecessary Trip - During Fault** - A Protection System operation for a Fault for which the Protection System is not intended to operate~~, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.~~.

6. **Unnecessary Trip - Other Than Fault** - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Generator Owner

   4.1.3 Distribution Provider

~~**Applicability:** SPS and RMS schemes are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion of the automation portion of relays are excluded from this standard.~~

Applicability: Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022-1. Some functions of relays are not used as protection but as control function or for automation, therefore, any operation of the control function portion or the automation portion of relays are excluded from this standard. See the Guidelines and Technical Basis section of the standard for detailed examples of non-protective functions.

4.2. Facilities

4.2.1 Protection Systems for ~~Facilities that are part of the BES~~BES Elements

~~**4.2.2** Facilities not included~~

4.2.2 Underfrequency Load Shedding (UFLS) that trips a BES Element

~~**4.2.2.1**~~ Special Protection Systems (SPS~~) or~~), Remedial Action Schemes (RAS~~)~~

~~**4.2.2.2**~~), and Undervoltage Load Shedding (UVLS)

4.2.3 ~~Relay functions not included (these~~ are ~~non~~excluded

~~**4.2.3**~~**4.2.4** Non-protective functions that may be imbedded within a Protection System~~)~~ are excluded

~~**4.2.3.1** Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~

~~**4.2.3.2** **Automation (e.g.** data collection)~~

5. Background:

A key element for BES reliability is the correct performance of Protection Systems. Monitoring BES Protection System events, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. PRC-004-3 Protection System ~~Misoperations~~Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In ~~the NOPR~~FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The ~~NOPR~~Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not usable to establish ~~a~~ consistent metrics for measuring Protection System performance. ~~The SAR includes establishing a~~ As such, the drafting team is removing the data obligation from the standard ~~with uniform applicability, revising the definition~~and is developing a data request under Section 1600 of ~~Misoperation, and clarifying reporting requirements~~the NERC Rules of Procedure. NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The data submitted as part of the data request will not be used for compliance or enforcement purposes. The removal of the data collection from the standard does not result in a reduction of reliability as Responsible Entities are required to retain evidence of compliance for audit and compliance purposes under the Compliance Section C 1.2 Evidence Retention portion of the standard.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet~~s~~ the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to determine the cause(s).

- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations of or associated with Special Protection Schemes, Remedial Action Schemes, and Under-Voltage Load Shedding are not addressed in this standard due to their inherent complexities. NERC intends to address these areas through future projects.

Note that the WECC Regional Reliability Standard PRC-004-WECC-1 relates to the reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

B. Requirements and Measures

R1. ~~Within 120 calendar days of an interrupting device operation in its Facility caused by a Protection System operation, each~~Each Transmission Owner, Generator Owner, and Distribution Provider shall: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

Rationale for R1: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The ~~SDT~~drafting team believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.

1.1 ~~Identify~~Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.

- If the entity ~~suspects a~~owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation.

~~1.1~~
- If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System

component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information.

~~1.2 Designate each Misoperation (if any).~~

- ~~Investigate each~~The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.

~~1.3~~1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation ~~(if any)~~shall investigate and document the findings ~~including a cause~~ for each Misoperation including a cause, if identified.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1 that may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date and time of each applicable interrupting device operation and ~~an indication~~indicates when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal ~~and receipt~~ of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date, time, Facility and equipment name associated with each Misoperation~~. Acceptable evidence for Part 1.3 may include, but is not limited to~~, a copy of a dated Misoperation investigation report or documented findings, which may include sequence of events, relay targets, summary of DME records for each Misoperation.

Rationale for R2: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule for a CAP. When the cause of a Misoperation is determined from implementing an action plan in accordance with Requirement R4, a CAP must be developed in accordance with Requirement R2.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation investigation process and for future reference.

R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop ~~and document~~ a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.

~~**Rationale for R2**: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, development of a schedule, or procurement of funds for a CAP.~~

~~In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close out the Misoperation investigation process and future reference.~~

R3. ~~For each Misoperation without an identified cause(s), the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or
- A declaration explaining why no further actions will be taken.

Rationale for R3: Where a Misoperation cause is not determined during the initial investigation~~,~~; implementing an action plan of additional investigation/monitoring may determine a cause~~.~~ and lead to the development of a CAP in accordance with Requirement R2. The 180 calendar ~~days~~day period is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

If the ~~investigation~~action plan completion does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close ~~out~~of the Misoperation investigation process and for future reference.

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R3 that must include a dated action plan or a dated declaration.

R4. ~~For each CAP or action plan, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall~~:~~ implement each CAP or action plan, and revise as needed through completion. [*Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]*

~~**4.1** Implement the CAP or action plan~~

~~**4.2** Maintain detailed implementation records of each CAP or action plan including dated information~~

~~**Rationale for R4**: The CAP or action plan must be fully implemented to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan.~~

Rationale for R4: The CAP or action plan must be completed to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan. When the cause of a Misoperation is determined from implementing an action plan, a CAP must be developed in accordance with Requirement R2.

~~surrounding any revision(s) and completion~~

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R4 that must include, but is not limited to, dated electronic or hard copy records which document the implementation of each CAP and action plan~~,~~ and the completion of actions ~~and revisions~~ for each CAP or action plan~~;~~. The evidence may also include dated work management program records, dated work orders, or dated maintenance records.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority (CEA)

- 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.~~Regional Entity or if the Responsible Entity is owned, operated or controlled by the Regional Entity, then the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity) to be responsible for compliance enforcement.~~

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 that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its ~~Compliance Enforcement Authority~~CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.

If a Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

~~Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 – Attachment 1 to the CEA within two calendar months following the end of each calendar quarter.~~

~~The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.~~

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Assessment, Operations Planning**	**Medium**	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than 120 calendar days but less than or equal to ~~130~~150 calendar days of the operation's occurrence. OR The responsible entity	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~130~~150 calendar days but less than or equal to ~~140~~160 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~140~~160 calendar days but less than or equal to ~~150~~170 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~150~~170 calendar days of the operation's occurrence. OR The responsible entity failed to identify and

			identified a Protection System operation that operated one of its BES interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System ~~O~~operation that operated one of its BES interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.~~3~~2.			review a Protection System operation that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1. ~~OR~~ ~~The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2.~~ OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.~~3~~2.

						OR The ~~responsible~~ entity ~~completed its investigation of a~~that owns the BES interrupting device but does not own the entire Protection System ~~Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's~~could not determine if the operation was correct and failed to notify the other owner(s) of the Protection System component~~contributed to the Misoperation, and failed to notify~~(s) and provide any requested investigative information ~~to that entity~~ in accordance with Requirement R1, Part 1.1.
R2	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more

			more than 60 calendar days but less than or equal to 70 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	more than 70 calendar days but less than or equal to 80 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	more than 80 calendar days but less than or equal to 90 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	than 90 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.
R3	**Operations Planning, Long-Term Planning**	**Medium**	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to ~~190~~210 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~190~~210 calendar days but less than or equal to ~~200~~220 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~200~~220 calendar days but less than or equal to ~~210~~230 calendar days following the ~~completion of the investigation~~associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than ~~210~~230 calendar days following the ~~completion of the investigation~~associated BES interrupting device operation. OR The responsible entity failed to develop~~, implement, and documented~~ an action plan~~,~~ or a declaration in

						accordance with Requirement R3.
R4	**Operations Planning, Long-Term Planning**	**High**	The responsible entity failed to revise ~~maintained records of~~ a CAP or action plan as needed in accordance with Requirement R4. ~~but the records were incomplete.~~	N/A	N/A	The responsible entity failed to implement a CAP or action plan in accordance with Requirement R4. ~~OR~~ ~~The responsible entity failed to maintain records of a CAP or action plan.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

The composite Protection System in the context of this standard is the total complement of protection for a system Element. All protection for a given Element such as primary, secondary, backup, pilot and non-pilot relay schemes are included in the composite Protection System for the Element. These individual schemes or systems may be isolated or function independently, but aggregate as part of one composite Protection System.

A Protection System is defined in the NERC Glossary of Terms as:

- 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.

Circuit breaker and other interrupting device mechanisms are not part of a Protection System.

A revised Misoperation definition is being proposed for industry adoption~~. It~~; the failure of an Element's composite Protection System to operate as intended. The definition includes the following ~~conditions:~~ categories:

(1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~A lack of target information, e.g. when a high-speed pilot system does not trip because a high-speed zone element trips first, is not a Misoperation. If a fault or abnormal condition is cleared within the time normally expected with proper functioning of at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation~~**The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.**

A failure of a transformer's composite Protection System to operate for a transformer Fault is an example of a "failure to trip" Misoperation. This type of Misoperation typically results in the Fault being cleared by remote backup Protection System operations.

A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "failure to trip" Misoperation as long as another component of the transformer's composite Protection System operated to clear the Fault. Please see category 3 to see if the "slow trip" classification applies to the operation.

A lack of target information, e.g. when a high-speed pilot system does not target because a high-speed zone element trips first, does not by itself constitute a Misoperation.

(2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~For example,~~**The failure** ~~to trip the generator by loss~~ **of** ~~field protection for~~ **a** ~~loss of field condition on that generator~~**Protection System component is not a Misoperation**~~.~~ **as long as the overall performance of the Protection System for the Element it is designed to protect is correct.**

A failure of a generator's composite Protection System to operate for a loss of field condition is an example of a "failure to trip" Misoperation. This type of Misoperation may require manual operator intervention.

A failure of a "primary" reverse power relay (or any other component) is not a "failure to trip" Misoperation as long as another component of the generator's composite Protection System operated to shut down the generator. Please see category 4 to see if the "slow trip" classification applies to the operation.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(3) A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed ~~f~~**Fault clearing associated with an installed high**~~-~~**-speed performance** ~~is~~**has not** ~~required by planning studies associated with~~**been identified to meet the dynamic stability performance requirements of the TPL standards** ~~or by~~**nor is it required to ensure coordination**~~requirements~~ **with other Protection Systems.**

A failure of a line's composite Protection System to operate as quickly as intended for a line Fault is an example of a "slow trip" Misoperation. This type of Misoperation typically results in remote backup Protection System operations before the Fault is cleared.

In many cases, high-speed protection is installed as part of the utility's standard practice without having the need for high-speed protection for meeting TPL requirements. A slow trip of this Protection System would not negatively impact the dynamic performance of the BES; so, it does not need to be reported. However, even if high-speed clearing is not required, the Protection Systems must coordinate to prevent an "unnecessary trip" Misoperation (e.g. an over trip).

The phrase "slower than intended" means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate.

The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.

Coordination with other Protection Systems refers to the need to ensure that relaying operates in the proper or planned sequence (i.e. the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

(4) A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate. ~~An example of this type of Misoperation is an over excitation condition where the protection designed to detect this condition operated slower than intended resulting in a higher degree of insulation stress than desired.~~

A failure of a generator's composite Protection System to operate as quickly as intended for an over excitation condition is an example of a "slow trip" Misoperation. This type of Misoperation may result in equipment damage.

The phrase "slower than intended" means the composite Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.

The non-Fault conditions cited in the definition are examples only, and do not constitute an all inclusive list.

(5) A Protection System operation for a Fault for which the Protection System is not intended to operate~~, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone.~~ .

An ~~example of~~ operation of a transformer's composite Protection System which over trips for a properly cleared line Fault is an example of an "unnecessary trip" Misoperation. For this type of Misoperation ~~is an over-reaching trip due to a lack of coordination between remote and local Protection Systems. Note: Operation of~~, the Fault is typically cleared properly by the faulted equipment's composite Protection System (line relaying, in this case) without the need for an external Protection System's operation.

An operation of a properly coordinated remote Protection Systems is not a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the local Protection System to clear the Fault ~~in adjacent zones is not~~. An interrupting device failure, a "failure to trip" Misoperation ~~of the~~, or a "slow trip" Misoperation may result in a proper remote Protection System ~~if the local Protection System of the faulted Element~~

~~fails to clear the Fault within the intended time; however, the failure of the local Protection System for the faulted zone is a Misoperation~~operation.

(6) A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate~~. These non~~, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Non-Fault conditions ~~may~~ include but are not limited to power swings, over excitation~~ or~~, loss of excitation ~~but could include even~~, frequency excursions and normal conditions. ~~For example,~~

An operation of a line's composite Protection System due to a relay failure during normal conditions ~~could conceivably cause~~is an ~~incorrect~~example of an "unnecessary trip ~~and a~~other than Fault" Misoperation.

In a second example, tripping a generator by the operation of loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation. In a third example, an impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because it was set with an excessive reach that unnecessarily restricted the line's load carrying capability. ~~This category of Misoperation cannot address at this time other operations during power swings unless the relay is clearly improperly set. Additional clarity on this specific issue will need to await completion of Phase III of Project 2010-13 on Relay Loadability which will address protective relay operations due to power swings as directed by FERC Order No. 733. Finally, an example of an operation that is not a Misoperation under this category is an unintended operation as a result of on-site maintenance, testing, construction or commissioning.~~

An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspection, construction or commissioning is not a Misoperation. However, once the maintenance, testing, inspection, construction or commissioning has been completed, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of the technical personnel.

This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.

The exclusion of a component failure, as long as the composite Protection System operates correctly, was based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. Covering these types of component failures within the standard constitutes additional administrative burden for types of failures that have no immediate reliability impacts.

Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.

~~Interrupting Device~~BES interrupting device operations which are initiated by ~~control systems~~non-protective functions, such as those associated with generator controls, or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard. Automation (e.g. data collection) is also not a protective function and is not subject to this standard.

A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation~~.~~ provided no in-service BES Elements are tripped. These types of operations are excluded ~~because~~when the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not Misoperations. Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.

In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. ~~-~~In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.

This standard addresses the reliability issues identified in the letter[1] from Gerry Cauley, NERC President and CEO, dated January ~~17, 2010~~7, 2011. "Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events…….. Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations." The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[2]; July 2011 "….a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

[1] http://www.nerc.com/news_pr.php?npr=723
[2] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

In the event of a natural disaster, note that 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 in relation to the timelines outlined in this standard.

Requirement R1

This requirement promotes the prudent evaluation of ~~all~~each Protection System operation~~s~~ to ~~designate~~determine if the operation was correct or a Misoperation, even those Misoperations~~, even those~~ difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed ~~Faults~~operations resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.

Requirement ~~1~~R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System.~~-~~ The ~~SDT~~drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the BES interrupting device owner ~~suspects~~does not own all of the Protection System and cannot determine that the ~~Misoperation~~Protection System operation was ~~caused by a~~correct, then notify the other owner(s) of the Protection System component~~ owned by another entity, they must notify that component owner and document the notification~~(s) and provide any requested investigative information. In this case, it is expected that both entities will work together to investigate the cause of the operation.

Protection Systems are made of many components. These components may be owned by more than one entity. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all the owners will communicate with each other, sharing any information freely, so that operations can be analyzed, Misoperations identified and corrective actions taken. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation.

Determining the cause of Protection System Misoperations is essential in developing an effective remedy to avoid future Misoperations. ~~The SDT~~The drafting team recognizes that there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. The drafting team believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in ~~an~~a Misoperation investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.

Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a single Protection System causes multiple BES interrupting device owners to be affected, the entities may work together to produce a common Misoperation investigation report. Similarly, if the BES interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report.~~ Each TO, GO, or DP would be expected to have a copy of the common investigation report.~~

~~An~~A Misoperation investigation report or documented findings may include the following information: 1) initial evidence, 2) probable causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records~~.~~ as appropriate. Probable causes are those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the cause. The conclusions should summarize the cause(s) substantiated by the evidence and findings of the tests and studies.

Requirement ~~2~~R2

If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. The drafting team recognizes there may be multiple causes for a Misoperation; in these circumstances the CAP would include a remedy for the identified causes. The 60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can be revised if additional causes are found. Based on industry experience and operational coordination timeframes, the ~~SDT~~drafting team believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule~~, or procurement of funds~~ for a CAP, or to prepare a declaration justifying the lack of a CAP.

The 120 day time period and the 60 day time period are distinct and within the context of Requirement R1 and Requirement R2 respectively, need to remain separate. With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days. Also, if the interrupting device owner is tardy in informing another Protection System component owner and using up much of the 120 day period, it still leaves a considerable amount of time (at least 60 days) to develop an action plan for further investigation by the Protection System component owner, or if a cause is determined the creation of the CAP.

Where there are multiple Protection System owners involved in a Misoperation, the one or more owners whose Protection System component(s) contributed to the Misoperation will create a CAP or declaration as required by Requirement ~~2~~R2. Owners whose Protection System components operated correctly do not need to create a CAP~~. All owners should update their investigation documentation to indicate which party or parties are performing a CAP to address the Misoperation~~.

Resolving Misoperations benefits the Protection System owner and the BES by ~~improving~~maintaining reliability and security. The CAP is an established tool for resolving operational problems. The NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".

Protection System owners are expected to exercise due diligence in the development and implementation of a CAP. Typically included would be any corrective actions taken to prevent recurrence (along with the date performed), ~~and~~ any corrective actions planned to be taken to prevent recurrence (along with the planned date~~).~~), and an evaluation of the CAP's applicability to other Protection Systems owned by the entity.

~~An example~~The evaluation of ~~a CAP for a Misoperation determined~~the CAP's applicability to ~~have been caused~~other Protection Systems owned by the entity is intended to encourage diligence in preventing similar Misoperations. The Protection System owner is responsible for determining the scope of the problem, and for including appropriate actions in the CAP. The evaluation may result in adding preemptive actions to the CAP. The CAP is complete when all specified actions are completed.

The following are examples of Corrective Action Plans (CAPs):

CAP Example 1 – Corrective actions for a failed relay ~~that has not been repaired might be: "Temporarily~~only:

> The impedance relay was removed ~~failed relay~~ from service on ~~xx/xx/xx. Plan to repair then return~~6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on ~~xx/xx/xx."~~6/5/12.
>
> ~~An example of a CAP for a Misoperation determined to have been caused by~~ Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred only occasionally within our system. This type of impedance relay is gradually being replaced with microprocessor relays as Protection Systems are modernized. It is therefore our assessment that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for our system.

CAP Example 2 - Corrective actions for a failed relay ~~that has been repaired might be: "Temporarily~~, and a program for preemptive actions at similar installations:

The impedance relay was removed ~~failed relay~~ from service on ~~xx/xx/xx. Repaired then returned relay~~ 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on ~~xx/xx/xx."~~6/5/12.

~~An example~~Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that a program should be established by 12/1/12 for wholesale preemptive replacement of capacitors in this type of impedance relay.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/12.

CAP Example 3 - Corrective actions for a ~~Misoperation suspected to have been caused by an intermittent relay failure might be: "Temporarily~~failed relay; and preemptive actions for similar installations:

The impedance relay was removed ~~suspect relay~~ from service on ~~xx/xx/xx. Replaced with like kind, and placed in~~ 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The capacitor was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on ~~xx/xx/xx."~~6/5/12.

Applicability to other Protection Systems: Undesired trips of this type of impedance relay due to capacitor failures have occurred frequently. It is therefore our assessment that preemptive replacement of capacitors in this type of impedance relay should be pursued.

It is planned to replace the impedance relay capacitors at stations A, B, and C by 9/1/12. It is planned to replace the impedance relay capacitors at stations D, E, and F by 11/1/12. It is planned to replace the impedance relay capacitors at stations G, H, and I by 2/1/13.

The impedance relay capacitor replacement was completed at stations A, B, and C on 8/16/12. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/26/12. The impedance relay capacitor replacement was completed at stations G, H, and I on 1/9/13.

CAP Example 4 - Corrective actions for a firmware problem; and preemptive actions for similar installations:

Fault records were provided to the manufacturer on 6/4/12. On 6/11/12, the manufacturer responded that the misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 6/12/12.

Applicability to other Protection Systems: Based on our risk assessment, we plan to install firmware version 3 at all of our installations that are determined to be version 2. Proposed completion date is 12/31/12.

The firmware replacements were completed on 12/4/12.

If the Misoperation cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners are required to make a declaration to this effect. A "no CAP declaration" would typically include the Misoperation cause and justification for taking no corrective action.

An example of a "no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is expected to be used sparingly.

~~CAPs should include an evaluation as to whether the entity's Protection Systems at other locations are also vulnerable to the same type of Misoperation.~~

~~Requirement 3~~

There are some cases where a Misoperation cause is outside of an entity's control and would result in a "no CAP declaration." Items that may be considered outside of an entity's control could be a non-registered entity communications provider problem or a transmission transformer tapped industrial customer who initiates a direct transfer trip to a registered entity's transmission breaker. Generally, situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control. The "outside an entity's control" declaration is expected to be used sparingly.

Requirement R3

If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).

At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days ~~is~~are the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)

Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.

An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."

An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."

An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review by xx/xx/xx."

If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this effect. A "no action plan" declaration~~"~~ would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.

An example of a "no action plan" declaration~~"~~ might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."

Requirement R4

~~Finally, the~~The goal of the standard has not been met unless ~~CAP(s)~~CAPs or action plans are actually implemented, as is required in Requirement R4. The responsible entity is required to implement and complete a CAP or action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The responsible entity is also required to complete the CAP or action plan, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.

The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement ~~2~~R2. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.

Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.

~~**Reporting:**~~

~~A review of the Transmission Availability Data System (TADS) data for the years 2008 – 2010 revealed that the fourth ranked initiating cause of BES outages not related to weather was "Failed Protection System Equipment." Given the high ranking of this metric, it is appropriate to collect data on Protection System Misoperations for analysis to drive improvements in Protection System reliability.~~

~~**Section C-1.4** requires periodic data reporting and references a common reporting format to facilitate consistent reporting of Misoperation data by all Transmission Owners, Generator Owners, and Distribution Providers. Reporting Misoperation data in a common format permits the ERO to analyze the data, develop meaningful metrics for measuring Protection System performance, identify trends in Protection System performance that negatively impact reliability, and identify lessons learned.~~

~~Analysis of data from all Misoperations across North America makes possible identification of issues and trends that may not be identifiable through analysis of smaller data sets on an entity or regional basis. Information regarding identified issues and trends and recommended actions will be shared with Transmission Owners, Generator Owners, and Distribution Providers through lessons learned or industry alerts. Sharing this information will permit recipients to take appropriate actions to drive improvements in Protection System performance.~~

~~The common reporting template also will improve the usefulness of metrics developed to track Protection System performance. While the most relevant category defined in TADS is titled "Failed Protection System Equipment," the title is not an accurate description of the information reported in the metric. This metric includes all Protection System Misoperations that are not related to human error, which is only a subset of all Protection System Misoperations. The Protection System Misoperations related to human error (e.g., miscoordinated settings, incorrect setting calculations, and errors in applying settings to the relay, etc.) are tracked separately from Protection System equipment-related Misoperations, and are grouped together with other human errors by a utility employee or contractor. Similarly, Protection System Misoperations related to failed equipment such as a failed CVT on the primary insulation side are reported under "Failed AC Substation Equipment." Reporting of Misoperations data using the common format specified in C-1.4 will permit development of metrics specific to Protection System Misoperations, with the potential to break down the metric by category of Misoperation (e.g., failure to trip, slow trip, unnecessary trip, etc.) and cause of Misoperation (ac system, dc system, as-left personnel error, incorrect setting/logic/design, and relay failures/malfunctions).~~

~~Reporting Misoperations and their CAPs or action plans provides a means of monitoring and assessing Misoperations. Reviewing and tracking this information provides a method~~

~~of validating the actions taken to address the causes of Misoperations. A second need for reporting Misoperations is to facilitate the identification of trends in Protection System performance that negatively impact reliability. Analyzing data from all Misoperations across North America will make it possible to identify trends that may not be discernible through analysis of smaller data sets on an entity or regional basis.~~

~~Misoperations and updates will be submitted to the Regional Entity on a quarterly basis per the following schedule:~~

~~**Reporting Quarter**~~	~~**Submission Date**~~
~~1st Quarter (Jan 1 – March 31)~~	~~May 31~~
~~2nd Quarter (Apr 1 – June 30)~~	~~August 31~~
~~3rd Quarter (July 1 – Sept 30)~~	~~November 30~~
~~4th Quarter (Oct 1 – Dec 31)~~	~~February 28~~

~~The two calendar months reporting of Misoperations that occurred within the quarterly reporting period corresponds to the recommendations provided by ERO-RAPA and also correlates to the time which the majority of Regional Entities were using in 2011. It is believed that two calendar months is a reasonable time for an entity to submit their Misoperations data after the close of a reporting period. Reporting and updating on a limited time interval and lag (from occurrence) aids in focusing on high trend items of common mode failures. A longer period of time for reporting could prevent high trend failures from being quickly recognized.~~

~~Examples of reporting:~~

1. ~~If a Misoperation occurred on March 30 but was not identified as a Misoperation until June 2, then this Misoperation would be reported in the second quarter reporting period.~~
2. ~~If the Misoperation in example 1 was not completely investigated in the second quarter but a cause was determined on July 2, then a resubmittal should be reported in the third quarter.~~
3. ~~If the Misoperation in examples 1 and 2 had its CAP completed on November 2, then a resubmittal indicating that the CAP was completed should be reported in the fourth quarter.~~

Implementation Plan

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standards drafting team proposes modifying the following approved definition:

Misoperation:

The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault -** A failure of a Protection System to operate for a Fault within the zone it is designed to protect. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

2. **Failure to Trip - Other Than Fault -** A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.

3. **Slow Trip - During Fault -** A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.

4. **Slow Trip - Other Than Fault -** A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault -** A Protection System operation for a Fault for which the Protection System is not intended to operate.

6. **Unnecessary Trip - Other Than Fault -** A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Background

PRC-004-3 Protection System Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

General Considerations

PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements.
- Underfrequency Load Shedding (UFLS) that trips a BES Element
- Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded
- Non-protective functions that may be imbedded within a Protection System are excluded

Effective Date of New or Revised Standards and Definitions

First day of the first calendar quarter that is twelve months beyond the date that PRC-004-3 is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The proposed definition of Misoperation shall become effective on the same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.

Implementation Plan for Requirements R1, R2, R3 and R4

Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.

Retirement of Existing Standards

The existing standards PRC-003-1 and PRC-004-2a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3.

Implementation Plan

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standards drafting team proposes modifying the following approved definition:

Misoperation: ~~Any of the following:~~

The failure of an Element's composite Protection System to operate as intended.

Any of the following is considered a Misoperation:

1. **Failure to Trip - During Fault -** A failure of a Protection System to operate for a Fault within the zone it is designed to protect. ~~(~~The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for ~~an~~the Element it is designed to protect is correct~~.)~~.
2. **Failure to Trip - Other Than Fault -** A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. ~~(~~The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for ~~an~~the Element it is designed to protect is correct~~.)~~.
3. **Slow Trip - During Fault -** A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. ~~(~~Delayed Fault ~~C~~clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance ~~is required~~has not been identified to meet the dynamic stability performance requirements of the TPL standards ~~or by~~nor is it required to ensure coordination ~~requirements~~ with other Protection Systems~~.)~~.
4. **Slow Trip - Other Than Fault -** A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.

5. **Unnecessary Trip - During Fault -** A Protection System operation for a Fault for which the Protection System is not intended to operate~~, excluding any remote Protection System operation that resulted from a failure to trip or slow trip of a local Protection System in a faulted adjacent zone~~.

6. **Unnecessary Trip - Other Than Fault -** A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.

Background

PRC-004-3 Protection System ~~Misoperations~~Misoperation Identification and Correction is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In ~~the NOPR~~FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The ~~NOPR~~Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

General Considerations

PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for ~~Facilities that are part of the BES~~BES Elements.

~~Facilities not included~~

- Underfrequency Load Shedding (UFLS) that trips a BES Element
- Special Protection Systems (SPS~~) or~~), Remedial Action Schemes (RAS~~)~~

- ~~•~~), and Undervoltage Load Shedding (UVLS)
- ~~Relay functions not included (these~~ are ~~non~~excluded
- Non-protective functions that may be imbedded within a Protection System~~)~~ are excluded
- ~~Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~
- ~~Automation (e.g. data collection)~~

Effective Date of New or Revised Standards and Definitions

First day of the first calendar quarter that is ~~six~~twelve months beyond the date that PRC-004-3 is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter that is ~~six~~twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The proposed definition of Misoperation shall become effective on the same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.

Implementation Plan for Requirements R1, R2, R3 and R4

Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter ~~six~~twelve months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter ~~six~~twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.

Retirement of Existing Standards

The existing standards PRC-003-1 and PRC-004-2a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3.

Unofficial Comment Form

Project 2010-05.1 Protection System Misoperations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the PRC-004-3 Standard. The comment form must be completed by **February 20, 2013**.

If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803-530-1963.

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Background Information

This posting is soliciting formal comment.

The second draft of PRC-004-3 was posted for a 45-day formal comment period with concurrent initial ballot from July 25 – September 7, 2012. Stakeholders from approximately 145 companies representing 9 of the 10 Industry Segments provided feedback. The Protection System Misoperation Standard Drafting Team (PSM SDT) has responded to all commenters and developed a third draft of the standard for Protection System Misoperation Identification and Correction based on stakeholder input. Changes to the standard include:

- Revisions to the definition of Protection System Misoperation.
- Revisions to the Applicability 'Facilities' section.
- Revisions to the Requirements and Measures.
- Modifications to the VSLs to reflect the changes in the requirements.
- Revisions to the Implementation Plan including extending the Effective Date from six months to twelve months following applicable regulatory approvals.
- Removal of the Misoperations reporting aspects from the standard.
- Modifications to the Guidelines and Technical Basis section to include more explanation and examples.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Based on stakeholder input, the drafting team revised the definition of a Misoperation. The categories as well as the introductory sentence of the definition were modified for clarity. The introductory sentence indicates that a Misoperation pertains to 'the failure of an Element's composite Protection System to operate as intended.' Do you agree with the revised definition? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

2. Requirement R1 was revised to to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs. Do you agree with these changes? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

3. The Measures and VSLs were revised to reflect changes to the requirements. Do you agree with these changes? If not, please provide specific reasons why not and alternative recommendations and justifications.

   ☐ Yes
   ☐ No
   Comments:

4. The drafting team modified the Guidelines and Technical Basis section to provide more supporting discussions, explanations, and examples for the various aspects of the standard. Do you have any specific suggestions for further improvements?

   ☐ Yes
   ☐ No
   Comments:

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

   Comments:

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1(Misoperations)

Mapping Document Showing Translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, and PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into PRC-004-3 — Protection System Misoperation Identification and Correction.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider
R1. Part 1.1. The Protection Systems to be reviewed and analyzed for Misoperations	PRC-004-3 Applicability Section 4.2	**4.2. Facilities** **4.2.1** Protection Systems for BES Facilities

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
(due to their potential impact on BES reliability).	Facilities.	**4.2.2** Underfrequency Load Shedding (UFLS) that trips a BES Element **4.2.3** Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded **4.2.4** Non-protective functions that may be imbedded within a Protection System are excluded
R1. Part 1.2. Data reporting requirements (periodicity and format) for Misoperations.	NERC Rules of Procedure, Section 1600 data request	N/A
R1. Part 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. • If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified. **R2.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken. **R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R1. Part 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. The standards development process mandates the standards be reviewed once every five years. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		See **PRC-004-3**
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider See **PRC-004-3**

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. • If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified. **R2.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken. **R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion.
R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: **1.1** Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. • If the entity owns both the BES interrupting

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		• A declaration explaining why no further actions will be taken. **R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	PRC-004-3 Requirement 4 NERC Rules of Procedure, Section 1600 data request	**R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion. N/A

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1(Misoperations)

~~Mapping Document~~

Mapping Document Showing Translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, and PRC-004-2a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into PRC-004-3 — Protection System Misoperation Identification and Correction.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
R1. Part 1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	PRC-004-3 Applicability Section 4.2 Facilities.	**4.2. Facilities** **4.2.1** Protection Systems for BES Facilities 4.2.2 Underfrequency Load Shedding (UFLS) that ~~are part of the~~trips a BES Element **4.2.**~~2 Facilities not included~~ ~~4.2.2.1~~3 Special Protection Systems (SPS~~) or~~), Remedial Action Schemes (RAS~~)~~ ~~4.2.2.2~~), and Undervoltage Load Shedding (UVLS) are excluded ~~4.2.3 Relay functions not included (these are non~~4.2.4 Non-protective functions that may be imbedded within a Protection System~~)~~ ~~4.2.3.1 Control (e.g. controlled shut down of generators or capacitor bank switching. Also see Guidelines and Technical Basis section for detailed examples)~~ ~~4.2.3.2 Automation (e.g. data collection)~~ are excluded
R1. Part 1.2. Data reporting requirements (periodicity and format) for Misoperations.	~~PRC-004-3~~ ~~Compliance~~NERC Rules of Procedure, Section ~~C 1.4 Additional Compliance~~	~~**C. 1.4. Additional Compliance Information**~~ ~~Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
	~~Information~~1600 data request	~~to the CEA within two calendar months following the end of each calendar quarter.~~ ~~The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.~~N/A
R1. Part 1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.**~~–~~ Each Transmission Owner, Generator Owner, and Distribution Provider shall: Within 120 calendar days of ~~an~~a BES interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ **1.1** ~~**1.1** Identify~~identify and review each Protection System operation. • If the entity ~~suspects a~~owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		owner(s) of the Protection System component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information. ~~1.2 Designate each Misoperation (if any).~~ ~~1.3 Investigate each~~o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation ~~(if any)~~shall investigate and document the findings ~~including a cause~~ for each Misoperation including a cause, if identified. **R2.** ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation:

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		• Develop~~ and document~~ a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** ~~For each Misoperation without an identified cause(s), the~~ Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of ~~its~~the associated BES interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken. **R4.** ~~For each CAP or action plan, the~~Each Transmission

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
		Owner, Generator Owner, or Distribution Provider shall~~:~~ ~~4.1 Implement the CAP or action plan~~ ~~4.2 Maintain detailed implementation records of~~ implement each CAP or action plan ~~including dated information surrounding any revision(s),~~ and revise as needed through completion.
R1. Part 1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	**4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**
review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	entities to follow. The standards development process mandates the standards be reviewed once every five years. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider See **PRC-004-3**
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	PRC-004-3 Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization. PRC-004-3 replaces the RRO procedures.	PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider See **PRC-004-3**

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.**~~–~~ Each Transmission Owner, Generator Owner, and Distribution Provider shall: Within 120 calendar days of ~~an~~a BES interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ **1.1** ~~**1.1** Identify~~identify and review each Protection System operation. • If the entity ~~suspects a~~owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information.

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		~~**1.2** Designate each Misoperation (if any).~~ ~~**1.3** Investigate each~~o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation ~~(if any)~~shall investigate and document the findings ~~including a cause~~ for each Misoperation including a cause, if identified. **R2.** ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** ~~For each Misoperation without an identified cause(s), the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of ~~its~~the associated BES interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken. **R4.** ~~For each CAP or action plan, the~~Each Transmission Owner, Generator Owner, or Distribution Provider

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		shall~~:~~ ~~4.1 Implement the CAP or action plan~~ ~~4.2 Maintain detailed implementation records of~~ implement each CAP or action plan ~~including dated information surrounding any revision(s),~~ and revise as needed through completion.
R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4	**R1.**~~–~~ Each Transmission Owner, Generator Owner, and Distribution Provider shall: Within 120 calendar days of ~~an~~a BES interrupting device operation in its Facility caused by a Protection System operation, ~~each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ 1.1 ~~1.1 Identify~~identify and review each Protection System operation. • If the entity ~~suspects a~~owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation • If the entity owns the BES interrupting device but does not own all of the Protection System

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) ~~owned by another entity contributed to a Misoperation, notify the owner of that Protection System component~~ and provide any requested investigative information. ~~1.2 Designate each Misoperation (if any).~~ ~~1.3 Investigate each~~o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. **1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation ~~(if any)~~shall investigate and document the findings ~~including a cause~~ for each Misoperation including a cause, if identified.

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		R2. ~~Within 60 calendar days of identifying the cause(s) of each Misoperation, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. **R3.** ~~For each Misoperation without an identified cause(s), the~~ Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete for each Misoperation without an identified cause: • Development of an action plan that identifies

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
		any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken. **R4.** ~~For each CAP or action plan, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall~~:~~ ~~**4.1** Implement the CAP or action plan~~ ~~**4.2** Maintain detailed implementation records of~~ implement each CAP or action plan ~~including dated information surrounding any revision(s)~~, and revise as needed through completion.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional	PRC-004-3 Requirement 4 ~~Compliance~~NERC Rules of Procedure, Section ~~C 1.4 Additional Compliance Information~~1600 data request	**R4.** ~~For each CAP or action plan, the~~Each Transmission Owner, Generator Owner, or Distribution Provider shall~~:~~ ~~**4.1** Implement the CAP or action plan~~ ~~**4.2** Maintain detailed implementation records of~~ implement each CAP or action plan ~~including dated information surrounding any revision(s)~~, and revise

Standard: PRC-004-2a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment**
Entity's procedures.		as needed through completion. ~~C. 1.4. Additional Compliance Information~~ ~~Each Transmission Owner, Generator Owner, and Distribution Provider that owns BES protection Systems will submit the data identified in PRC-004 - Attachment 1 to the CEA within two calendar months following the end of each calendar quarter.~~ ~~The CEA will report the Misoperation information provided by the responsible entities to NERC on a quarterly basis.~~ N/A

Project 2010-05.1 – PRC-004-3: Protection System Misoperations

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

PRC-004-3 has four (4) requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. The revised standard requires entities to identify and review Protection System operations and designate each Misoperation; then investigate each Misoperation and document the findings. If a cause is identified, the entity either creates a Corrective Action Plan (CAP) or writes a declaration that they cannot correct the misoperating device(s). If a cause is not identified, the entity either creates an action plan for additional investigation or a writes a declaration that no further work will be done. The next step is to implement and complete the CAP or action plan. If the action plan leads to the determination of a cause, then the entity would either create a Corrective Action Plan (CAP) or write a declaration. The requirements recognize and encompass the possibility that components of a Protection System can be owned by different entities.

The requirements of PRC-004-3 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-WECC-1, EOP-008-1, PRC-004-2a and of TPL-001-2 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1, R2 and R3 are assigned a VRF of Medium, while Requirement R4 is assigned a VRF of High.

PRC-004-3 Requirements R1, R2 and R3 are related to identifying Protection System operations, designating Misoperations, investigating Misoperations and developing Corrective Action Plans (CAP) or action plans. The SDT determined that the assignment of a VRF of Medium was consistent with the NERC criterion that states "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…"

PRC-004-3 Requirement R4 relates to implementing and completing CAPs or action plans. The SDT determined that the assignment of a VRF of High was consistent with the NERC criterion that states "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…"

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has assigned a Medium VRF which is consistent with EOP-008-1 Requirement R8 (which is similar in nature to PRC-004-3 Requirement R1.)
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 120 calendar days but less than or equal to 150 calendar days of the operation's occurrence. OR The responsible entity identified a Protection System operation that operated one of its BES interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System operation that operated one of its BES interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 150 calendar days but less than or equal to 160 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 160 calendar days but less than or equal to 170 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 170 calendar days of the operation's occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1. OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.2. OR The entity that owns the BES interrupting device but does not own the entire Protection System could not determine if the

VRF and VSL Justifications – PRC-004-3, R1			
accordance with Requirement R1, Part 1.2.			operation was correct and failed to notify the other owner(s) of the Protection System component(s) and provide any requested investigative information in accordance with Requirement R1, Part 1.1.

VRF and VSL Justifications – PRC-004-3, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to

VRF and VSL Justifications – PRC-004-3, R2	
	bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.

VRF and VSL Justifications – PRC-004-3, R2			
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the identification of the cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the identification of the cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the identification of the cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the identification of the cause of the Misoperation. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.

VRF and VSL Justifications – PRC-004-3, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely

<table>
<tr><th colspan="4">VRF and VSL Justifications – PRC-004-3, R3</th></tr>
<tr><td></td><td colspan="3">to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.</td></tr>
<tr><td>FERC VRF G5 Discussion</td><td colspan="3">Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:
This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.</td></tr>
<tr><td colspan="4">Proposed VSL</td></tr>
<tr><td>Lower</td><td>Moderate</td><td>High</td><td>Severe</td></tr>
<tr><td>The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to 210 calendar days following the associated BES interrupting device operation.</td><td>The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 210 calendar days but less than or equal to 220 calendar days following the associated BES interrupting device operation.</td><td>The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 220 calendar days but less than or equal to 230 calendar days following the associated BES interrupting device operation.</td><td>The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than 230 calendar days following the associated BES interrupting device operation.
OR
The responsible entity failed to develop an action plan or a declaration in accordance with Requirement R3.</td></tr>
</table>

VRF and VSL Justifications – PRC-004-3, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is consistent with PRC-004-2a, Requirements R1 and R2, PRC-004-WECC-1 Requirement R2.1, and TPL-001-2 Requirement R2 Part 2.7 which have approved VRFs of High.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion for a High VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does contain obligations that are administrative in nature but they support the high risk

VRF and VSL Justifications – PRC-004-3, R4			
	reliability objective; the assigned VRF of High is appropriate for the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP or action plan in accordance with Requirement R4.

VRF and VSL Justifications – PRC-004-3, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of the requirement that are not equal in importance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the previous severity level and does not lower the current level of compliance for the similar Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, R4	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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.

NERC
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RELIABILITY CORPORATION

Project 2010-05.1 – PRC-004-3: Protection System Misoperations

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

PRC-004-3 has four (4) requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. The revised standard requires entities to identify and review Protection System operations and designate each Misoperation; then investigate each Misoperation and document the findings. If a cause is identified, the entity either creates a Corrective Action Plan (CAP) or writes a declaration that they cannot correct the misoperating device(s). If a cause is not identified, the entity either creates an action plan for additional investigation or a writes a declaration that no further work will be done. The next step is to implement and complete the CAP or action plan. If the action plan leads to the determination of a cause, then the entity would either create a Corrective Action Plan (CAP) or write a declaration. The requirements recognize and encompass the possibility that components of a Protection System can be owned by different entities.

The requirements of PRC-004-3 do not map, one-to-one, with the requirements of the legacy standards. The new requirements comingle various reliability attributes of the legacy standards with new reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-WECC-1, EOP-008-1, PRC-004-2a and of TPL-001-2 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1, R2 and R3 are assigned a VRF of Medium, while Requirement R4 is assigned a VRF of High.

PRC-004-3 Requirements R1, R2 and R3 are related to identifying Protection System operations, designating Misoperations, investigating Misoperations and developing Corrective Action Plans (CAP) or action plans. The SDT determined that the assignment of a VRF of Medium was consistent with the NERC criterion that states "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…"

PRC-004-3 Requirement R4 relates to implementing and completing CAPs or action plans. The SDT determined that the assignment of a VRF of High was consistent with the NERC criterion that states "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…"

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	Medium
NERC VRF Discussion	Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts that all support the reliability objective so only one VRF was assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The SDT has assigned a Medium VRF which is consistent with EOP-008-1 Requirement R8 (which is similar in nature to PRC-004-3 Requirement R1.)
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify and review each Protection System operation to designate Misoperations, investigate each Misoperation and document the findings 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.

VRF and VSL Justifications – PRC-004-3, R1			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than 120 calendar days but less than or equal to ~~130~~150 calendar days of the operation's occurrence. OR The responsible entity identified a Protection System operation that operated one of its BES interrupting devices but failed to review the operation in accordance with Requirement R1, Part 1.1. OR The responsible entity completed its review of a Protection System ~~O~~operation that operated one of its BES interrupting devices in 120	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~130~~150 calendar days but less than or equal to ~~140~~160 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~140~~160 calendar days but less than or equal to ~~150~~170 calendar days of the operation's occurrence.	The responsible entity performed the actions in accordance with Requirement R1, Parts 1.1 ~~–~~and 1.~~3~~2 in more than ~~150~~170 calendar days of the operation's occurrence. OR The responsible entity failed to identify and review a Protection System operation that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1. ~~OR~~ ~~The responsible entity completed its review of a Protection System operation that operated one of its interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to designate the operation as a Misoperation in accordance with Requirement R1, Part 1.2.~~

VRF and VSL Justifications – PRC-004-3, R1			
calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.~~3~~2.			OR The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.~~3~~2. OR The ~~responsible~~ entity ~~completed its investigation of a~~that owns the BES interrupting device but does not own the entire Protection System ~~Operation that operated one of its interrupting devices in 120 calendar days and suspected that another entity's~~could not determine if the operation was correct and failed to notify the other owner(s) of the Protection System component ~~contributed to the Misoperation, and failed to notify~~ (s) and provide any requested investigative information ~~to that entity~~ in accordance with Requirement R1, Part 1.1.

VRF and VSL Justifications – PRC-004-3, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to

VRF and VSL Justifications – PRC-004-3, R2	
	bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.

VRF and VSL Justifications – PRC-004-3, R2			
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation.	The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the ~~completion~~identification of the ~~investigation or receiving notification~~cause of the Misoperation. OR The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.

VRF and VSL Justifications – PRC-004-3, R2	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	Medium
NERC VRF Discussion	Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop an action plan for a Misoperation without an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely

VRF and VSL Justifications – PRC-004-3, R3			
	to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than 180 calendar days but less than or equal to ~~190~~210 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~190~~210 calendar days but less than or equal to ~~200~~220 calendar days following the associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, in more than ~~200~~220 calendar days but less than or equal to ~~210~~230 calendar days following the ~~completion of the investigation~~associated BES interrupting device operation.	The responsible entity developed an action plan, or made a declaration in accordance with Requirement R3, more than ~~210~~230 calendar days following the ~~completion of the investigation~~associated BES interrupting device operation. OR The responsible entity failed to develop~~, implement, and documented~~ an action plan~~,~~ or a declaration in accordance with Requirement R3.

VRF and VSL Justifications – PRC-004-3, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level 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.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	High
NERC VRF Discussion	Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion 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 Parts ~~that all support the reliability objective~~ so only one VRF was assigned~~; therefore no conflict(s) exist~~.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: The requirement is consistent with PRC-004-2a, Requirements R1 and R2, PRC-004-WECC-1 Requirement R2.1, and TPL-001-2 Requirement R2 Part 2.7 which have approved VRFs of High.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a CAP or action plan to address an identified Misoperation could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. This is a planning requirement that meets the NERC criterion for a High VRF.

VRF and VSL Justifications – PRC-004-3, R4			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does contain obligations that are administrative in nature but they support the high risk reliability objective; the assigned VRF of High is appropriate for the requirement.		
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity ~~maintained records of~~failed to revise a CAP or action plan ~~but the records were incomplete~~as needed in accordance with Requirement R4.	N/A	N/A	The responsible entity failed to implement a CAP or action plan~~.~~ ~~OR~~ ~~The responsible entity failed to maintain records of a CAP or action plan~~ in accordance with Requirement R4.

VRF and VSL Justifications – PRC-004-3, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—~~There is an incremental aspect to~~The VSLs cover aspects of the ~~VSLs for incomplete documentation and a binary aspect for failure to implement~~requirement that are not equal in importance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This VSL is consistent with the previous severity level and does not lower the current level of compliance for the similar Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level 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.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

VRF and VSL Justifications – PRC-004-3, R4	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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.

A. Introduction

1. **Title: Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**

2. **Number:** PRC-003-1

3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Regional Reliability Organization

5. **Effective Date:** May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:

R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).

R1.2. Data reporting requirements (periodicity and format) for Misoperations.

R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.

R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.

R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.

M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.

M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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.	01/20/06

A. Introduction

1. **Title: Analysis and Mitigation of Transmission and Generation Protection System Misoperations**

2. **Number:** PRC-004-1a

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **Effective Date:** To be determined

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization procedures developed for PRC-003 R1.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for PRC-003 R1.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Reliability Organization procedures developed for PRC-003 R1.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Transmission Owners and Distribution Providers that own a Transmission Protection System:

2.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R1, but documentation of Corrective Action Plans is incomplete.

2.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R1 and documentation of Corrective Action Plans is incomplete.

2.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R1 and there are no associated Corrective Action Plans.

2.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to Requirement 3.

3. Levels of Non-Compliance for Generator Owners

3.1. Level 1: Documentation of Misoperations is complete according to PRC-004 R2, but documentation of Corrective Action Plans is incomplete.

3.2. Level 2: Documentation of Misoperations is incomplete according to PRC-004 R2 and documentation of Corrective Action Plans is incomplete.

3.3. Level 3: Documentation of Misoperations is incomplete according to PRC-004 R2 and there are no associated Corrective Action Plans.

3.4. Level 4: Misoperations have not been analyzed and documentation has not been provided to the Regional Reliability Organization according to R3.

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
1	February 7, 2006	Adopted by the Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	

Appendix 1

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations

2. **Number:** PRC-004-2

3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Transmission Owner.

   4.2. Distribution Provider that owns a transmission Protection System.

   4.3. Generator Owner.

5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2	TBD	Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised.

Standards Announcement

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations) PRC-004-3

Successive Ballot and Non-Binding Poll is now open through February 20, 2013

Now Available

A successive ballot of **PRC-004-3** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) is now open **through 8 p.m. Eastern on Wednesday, February 20, 2013**.

Instructions
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 recirculation ballot.

Background
PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)
PRC-004-3

Formal Comment Period Open: January 22, 2013 – February 20, 2013

Upcoming:
Successive Ballot and Non-Binding Poll: February 11-20, 2013

Now Available

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is now open through 8 p.m. Eastern on **Wednesday, February 20, 2013**.

A successive ballot of **PRC-004-3** and non-binding poll of the associated VRFs and VSLs will be conducted beginning on **Monday, February 11, 2013 through 8 p.m. Eastern on Wednesday, February 20, 2013**.

Instructions
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 recirculation ballot.

Background
PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

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Standards Announcement

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)
PRC-004-3

Successive Ballot Results

Now Available

A successive ballot of **PRC-004-3** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Wednesday, February 20, 2013**.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the successive ballot.

Approval	Non-binding Poll Results
Quorum: 77.62% Approval: 50.66%	Quorum: 75.38% Supportive Opinions: 50.60%

Next Steps
The drafting team will consider all comments received during the formal comment period to determine the next steps.

Background
PRC-004-3 Protection System Misoperations is a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In the NOPR, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a.

Project 2010-05.1 is an important part of the ERO's strategic goal to develop technically sufficient standards with requirements that provide clear and unambiguous performance expectations and reliability benefits.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Reliability Standards Analyst, at monica.benson@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-05.1 Protection Systems: Misoperations Successive Jan 2013_in
Ballot Period:	2/11/2013 - 2/20/2013
Ballot Type:	Initial
Total # Votes:	333
Total Ballot Pool:	429
Quorum:	**77.62 % The Quorum has been reached**
Weighted Segment Vote:	50.66 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	113	1	41	0.471	46	0.529	6	20
2 - Segment 2.	9	0.6	4	0.4	2	0.2	3	0
3 - Segment 3.	107	1	32	0.444	40	0.556	5	30
4 - Segment 4.	33	1	7	0.318	15	0.682	2	9
5 - Segment 5.	93	1	26	0.4	39	0.6	6	22
6 - Segment 6.	54	1	18	0.462	21	0.538	5	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	11	0.6	5	0.5	1	0.1	1	4
9 - Segment 9.	2	0.1	1	0.1	0	0	0	1
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	**429**	**6.9**	**138**	**3.495**	**166**	**3.405**	**29**	**96**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	paul B johnson	Negative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Negative	

1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	

1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Negative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	

3	City of Austin dba Austin Energy	Andrew Gallo	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson		
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Negative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Negative	
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Negative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Negative	
3	Old Dominion Electric Coop.	Bill Watson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	PacifiCorp	Dan Zollner	Negative	
3	Pepco Holdings, Inc.	Mark R Jones	Negative	

3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos	Abstain	
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Negative	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak	Mike D Kukla	Negative	

	power plant project			
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Bridgeport Energy	Cleyton Tewksbury	Negative	
5	Caithness Long Island, LLC	Jason M Moore		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tallahassee	Karen Webb	Negative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	El Paso Electric Company	David Hawkins	Abstain	
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
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	Negative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	MidAmerican Energy Co.	Neil D Hammer	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Negative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Negative	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	
5	Public Utility District No. 1 of Chelan County	John Yale	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		

5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	Turlock Irrigation District	Marty Rojas		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Tony Soto	Abstain	
6	Entergy Services, Inc.	Terri F Benoit	Negative	
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	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Kelly Cumiskey	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	

6	Snohomish County PUD No. 1	William T Moojen		
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Turlock Irrigation District	Amy Petersen	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	
8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz		
8		Merle Ashton		
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Non-binding Poll Results

Project 2010-05.1 Protection Systems (Misoperations)

Ballot Results	
Non-binding Poll Name:	Project 2010-05.1 Non-binding Poll - Protection Systems -Misoperations
Poll Period:	2/11/2013 - 2/20/2013
Total # Opinions:	299
Total Ballot Pool:	398
Summary Results:	75.38% of those who registered to participate provided an opinion or an abstention; 50.60% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	paul B johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Negative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Negative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		

1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
1	Entergy Transmission	Oliver A Burke	Negative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Florida Power & Light Co.	Mike O'Neil	Negative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Negative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Abstain	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	

1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik		
1	Southern California Edison Company	Steven Mavis	Negative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	Turlock Irrigation District	Esteban Martinez	Abstain	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Negative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	
2	Midwest ISO, Inc.	Marie Knox	Negative	
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	

2	PJM Interconnection, L.L.C.	stephanie monzon	Abstain	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson		
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Negative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock		
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr		
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger	Negative	
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski		
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Negative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	

3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Mississippi Power	Jeff Franklin	Negative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson	Negative	
3	Oklahoma Gas and Electric Co.	Gary Clear	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	PacifiCorp	Dan Zollner	Abstain	
3	Pepco Holdings, Inc.	Mark R Jones	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	Buckeye Power, Inc.	Manmohan K Sachdeva	Negative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of Redding	Nicholas Zettel	Negative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer		
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	

5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer		
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	Bridgeport Energy	Cleyton Tewksbury	Negative	
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Negative	
5	City of Tallahassee	Karen Webb	Negative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy, Inc.	Mike D Hirst	Negative	
5	Colorado Springs Utilities	Jennifer Eckels		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	Essential Power, LLC	Patrick Brown	Negative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
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	Negative	
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Negative	
5	Luminant Generation Company LLC	Mike Laney		
5	Manitoba Hydro	S N Fernando	Affirmative	

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	
5	MidAmerican Energy Co.	Neil D Hammer	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Negative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Sacramento Municipal Utility District	Bethany Hunter	Negative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
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5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	U.S. Bureau of Reclamation	Martin Bauer		
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6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	

6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Negative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil		
6	Entergy Services, Inc.	Terri F Benoit	Negative	
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	Negative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	Progress Energy	John T Sturgeon		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Negative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Abstain	
6	Snohomish County PUD No. 1	William T Moojen		
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson	Negative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	

8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz		
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Negative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
10	Midwest Reliability Organization	William S Smith		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Name (53 Responses)
Organization (53 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (12 Responses)
Comments (76 Responses)
Question 1 (60 Responses)
Question 1 Comments (64 Responses)
Question 2 (62 Responses)
Question 2 Comments (64 Responses)
Question 3 (48 Responses)
Question 3 Comments (64 Responses)
Question 4 (56 Responses)
Question 4 Comments (64 Responses)
Question 5 (0 Responses)
Question 5 Comments (64 Responses)

Group
PacifiCorp
Ryan Millard
No
PacifiCorp believes that the definition used for a Slow Trip During Fault misoperation on Page 4 should be amended to provide more clarity. The current definition reads as follows: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.” PacifiCorp suggests changing “identified to meet” to “identified as necessary to meet.”
No
In the second draft of PRC-004-3 PacifiCorp commented that the 120-day time limit in R1 is insufficient. PacifiCorp maintains that when two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase of 60 days for each entity to complete their respective activities in sequence. This would increase the total from 120 to 180 in R1.
No
PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a “Lower” and a “Severe” VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional 30 days late should not increase the VSL from “Lower” to “Severe.” A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity’s failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days. PacifiCorp recognizes that the drafting team has made this change for the “Lower” VSL in Draft 3, but the remaining VSLs still reflect the 10 day timeframe. Moreover, in keeping with PacifiCorp’s comment under Question 1, the “Lower” VSL should be amended from 120 calendar days to 180 calendar days to allow each entity enough time to complete their respective activities before incurring a violation of the standard.
No
Individual
Greg Froehling
Rayburn Country Electric Cooperative

No
I suggest using the word “entire” versus “composite” for clarity sake. composite (adj) Merriam Webste of or relating to a very large family entire (adj) Merriam Webster having no element or part left out ELEMENT NERC Glossary Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.
Yes
Yes
Yes
Prefer the term "entire" to "composite" again for clarity sake since entire seems more intuitive in nature rather than composite which requires some anylitical thought to apply it. Example, a transformers entire protection system is slow to operate. Versus, a transformers composite protection system is slow to operate.
Group
Midwest Reliability Organization NERC Standards Review Forum (NSRF)
Russel Mountjoy
No
The NSRF would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn’t have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips.
No
The NSRF believes there should be exception for Acts of Nature such as tornados, ice storms and other natural disasters with, at minimum, the 120 day rule being waived. In previous comments the SDT agreed with this concern but did not add this exception. A wide spread thunderstom with heavy lightning can set off multiple trips and recloses in a short time. There should be a process to excempt such events. Please verify that reclosing relays are not within scope of this Reliability Standard.
Yes
The NSRF appreciates the addition of the Application Guide at the end of the Standard. The Application Guide will help NERC, the Regional Entities and Registered Entities to move away from a zero defact CMEP process.
For R2, depending on time of year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs for some entities. Also, the first bullet under R2 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies.
Group
Colorado Springs Utilities
Charles Morgan
Yes
No
Please consider clarification of the terms “BES Protection System”, “Protection System”, “BES interrupting device” and “interrupting device” throughout the proposed standard. Specifically in R1.1

the proposed requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. The wording of this requirement infers that the proposed standard is intended to include investigation of non-BES protection systems that cause the operation of a BES interrupting device. While such investigation is sound business practice, it may be outside the intended scope of the standard. An example would be the operation of a load serving transformer (say a 230kv to 13.2 kv unit) differential Protection System that operates both a BES interrupting device (a 230kv circuit breaker) and a non-BES interrupting device (a 13.2kv circuit breaker). The stated purpose of this standard is to “Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems” and is supported by the terminology used in the opening paragraph of the Background statement and the content of the Compliance section. Operation of a load serving facility protection system normally will have no impact on the reliability of the BES unless its failure to operate results in a subsequent operation of a BES bus differential Protection System or BES transmission element Protection System, for example. A similar argument can be offered for operation of protection system on non-BES radial lines and local network that cause operation of a high-side interrupting device which may also be part of a BES Protection System. Based on this line of thinking, it is proposed that the wording of requirement 1.1 be revised to state “Within 120 calendar days of an interrupting device operation in its Facility caused by a BES Protection System operation, identify and review each BES Protection System operation.” The wording of Requirements R1.2 and R3 should also be modified for consistency.
Yes
No
As noted in the response regarding R1. We believe that the specific terms need to be clarified in R3 as well to clarify the intended scope of covered situations.
Individual
John Miller
Georgia Transmission Corp
Yes
6. Unnecessary Trip - Other Than Fault: ...is not intended to operate. An Operation caused by on-site maintenance, testing, inspection, construction or commissioning activities on the designated Protection System are not considered as a Misoperation. alternatively: ...is not intended to operate. Operation of a Protection System that is not the focus of on-site maintenance, testing, inspection, construction or commissioning activity is considered a Misoperation. Suggested to highlight the second sentence in the 4th paragraph for defintition 6 in the Application Guidelines.
Yes
While reporting falls under 1600, should PRC-004 clarify which of the two should file the Misoperation?
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes

No
The Protection System component owner who does not also own the interrupting device may be placed in a non-compliant situation through no fault of their own. Their compliance is contingent upon a timely notification from the owner of the BES interrupting device. If the notification is not made in a timely fashion to allow for investigation the Protection System component owner would be non-compliant for not conducting an investigation and documenting the findings within 120 days. For this situation the BES interrupting device owner should have an abbreviated time frame to notify the Protection System component owner to provide sufficient time to collect the appropriate information and investigate the operation. Conversely, the owner of the Protection System component could be granted more time to investigate (i.e. 120 days from the notification by the BES interrupting device owner). A misoperation investigation if Protection Systems are shared between two or more entities is often a joint effort. The Application Guide clearly defines that “it is expected that both entities will work together to investigate the cause of the operation”, which is desired. This is not clearly defined in R1 and should be clarified. The Application Guide should indicate that this notification should be done as soon as possible.
No
We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
No
The Compliance Section of Standard has “The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period.” The word “open” should precede not only investigation, but action plan and CAP for clarity. It should be made to read “open investigation, open action plan, or open CAP even if the BES interrupting device operation occurred prior to the current audit period”. What is an Entity’s compliance obligation for an open investigation or open action plan that occurred prior to regulatory approval of this Standard but in the current audit period of an entity? The new standard establishes specific time limits. If an entity has an operation to investigate the day prior to the compliance obligation date, does the 120 day time limit apply the day the Standard is obligatory? Regarding the Implementation Plan for Requirements R1, R2, R3 and R4: “Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months” (this is the compliance obligation date) “following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard.” In this section of the Implementation Plan, what is meant by “new”? Is “new” any operation that occur after the compliance obligation date, or during the window of implementation between regulatory approval and compliance obligation date?
Individual
Alice Ireland
Xcel Energy
No
a. (This is the single issue causing us to vote negative.) Many generating units with legacy electromechanical protective relay based protection systems do not have DME for high-speed recording of relay-operation events. Although the generating circuit breakers may be on the HV side of GSU transformers and may be monitored via the associated substation DME, the initiating signals from protective relays on the generator side of the GSU may not provide an input or trigger signal to the substation DME. As such, there is little or no value in requiring Generator Owners to try to identify and analyze slow trip events when such data to perform the analysis is not required to be available. In particular, we are concerned that examples provided in the Slow to Trip – Other than Fault bullet of the Misoperation definition (undervoltage, over excitation and loss of excitation) point explicitly toward application of this portion of the definition towards Generator Owners. We are concerned how various auditors may judge entirely qualitative evaluations of the adequacy of GO Protection System performance for Slow to Trip – Other than Fault events when DME is not available, nor required, to quantify performance. b. Under "Slow Trip - During Fault", is the phrase “Delayed Fault clearing"

intended to be the same as the Glossary term “Delayed Fault Clearing”? If not, the similarity of the existing usage with the defined term introduces ambiguity and confusion about intent. Suggest rewording the second sentence under "Slow Trip - During Fault" to eliminate this potential confusion. Note that similar confusion between the term “Delayed Clearing” used in TPL Standards and the Glossary term “Delayed Fault Clearing” resulted in the NERC Interpretation Request 2012-INT-02.
Yes
Yes
No
It is important to be able to see the draft RSAW, as it relates to what kind of evidence, if any, would be required to demonstrate accurate assessment of a slow trip. This could be particularly problematic, as not all have DME installed to be able to capture data to be able to measure both the start and stop of the operation.
Individual
Michael Moltane
ITC Holdings
Yes
Yes
Yes
Yes
We have no issues with the guidelines, provided there is clarification that the guidelines are not to be used to support audit data request or findings.
Individual
John Seelke
Public Service Enterprise Group
Yes
No
R1 addresses the situation where a BES interrupting device operation may be the result of the operation of a Protection System operation owned by an entity that does not own the BES interrupting device. As written, the owner of the BES interrupting device has no deadline to notify the owners of other Protection Systems when cannot determine that the Protection System operation was correct (the second bullet in Part 1.1). R1 presently allows 120 calendar days in total for the owner of the BES interrupting device to notify the other Protection System owners and for those other owners to determine if their Protection System operated correctly and if they did not, to document each Misoperation, including a cause if one can be identified. As drafted, the owner of the BES interrupting device could notify the other Protection System owners on the 119th day following the operation of its interrupting device, making it impossible for those other Protection System owners to perform their required analysis by the 120th day. The change identified to Part 1.1 below requires the owner of the BES interrupting device to make a notification to the other Protection System owners within 60 calendar days of the operation of its BES interrupting device if the situation described above occurs. The changes to Part 1.2 below allows either Protection System owner 90 calendar days to document the findings of each Protection System Misoperation that may have occurred, making the total number of days allowed from the date of the operation of the BES interrupting device 150 calendar

days. Only 30 calendar days has been added to the timeline, but this additional 30 days is needed to correct the potential inequity for owners of Protection Systems that do not own the BES interrupting device to complete their analysis. For consistency, 30 calendar days was added to the R3 timeline of 180 days, making it 210 days from the date of the operation of the associated BES interrupting. R2 is unchanged, but is shown for completeness. We have also added a provision in a footnote that allows a Regional Entity to extend deadlines that are referenced to the operation date of a BES interrupting device for instances such as natural disasters. Personnel that might normally evaluate the operation of a Protection System may not be available to do so due to their involvement in restoration efforts. Here is our suggested changes. Additional language is CAPITALIZED. R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 Within [delete "120"] 60 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation AND [FOOTNOTE 1];. • If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation, OR;. • If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. FOOTNOTE 1: Such 60 day period and subsequent periods in the standard that have a deadline that references the operation date of a BES interrupting device may be extended by the Regional Entity for instances such as a natural disaster. 1.2 Within the same [delete "120 day period"] 150 CALENDAR DAYS of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified. R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 210 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] • Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or • A declaration explaining why no further actions will be taken.
Did not review.
No
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
No
M1 – DME is not defined. M3 - What was the reason for removing the words at the end 'explaining why no further investigation or actions will be taken' - these words are helpful and should be retained. VSLs – R1 – Severe VSL – the final option in this column seems to suggest that you would need both a failure to notify the other owners AND a failure to provide any investigative information. It doesn't contemplate a situation where an entity may have notified the other owners but failed to provide investigative information.

No
Background - The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". Moreover, the terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above. R2 - the words 'If a cause is identified' after the words 'cause(s) of each Misoperation' would be helpful. The way It reads, R2 is only applicable if a cause is identified and R3 is applicable if a cause if not identified so the Measures for each should be drafted in a way that makes that point clear. R3 – the words 'caused by a Protection System operation' should be added after BES interrupting device operation to make the wording consistent with the other requirements. R4 – In reading the rationale for R4, it states that if a cause of a Misoperation is determined when implementing the action plan, you go back to R2 and develop a CAP. This isn't evident on the face on the wording of the standard and the Rationale will be deleted going forward. R4/M4 – should be consistent with use of 'and' or 'or' when referring to the CAP and action plan, perhaps best option is to use 'and/or'. Compliance – 1.1 – Manitoba Hydro has never before seen a reference to the definition of CEA per the NERC Rules of Procedure in this section, it seems unnecessary. Compliance - the phrase BES Protection System is elsewhere referred to as Protection System for Facilities that are part of the BES which seems more accurate and should be consistently used.
Individual
Patrick Brown
Essential Power, LLC
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: -The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. -Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. -The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). -Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own…" by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to …then list the items once.
No
See comments to question 2
Yes
The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks

linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?
Group
Mary Jo Cooper
Mary Jo Cooper
Yes
Yes
No
This Standard allows 120 days for the entity to investigate the operation. We do not feel that this activity warrants a severe violation factor if only 1 operation was investigated 50 days later. We agree that if an activity has a significant impact on the BES than the violation severity level should be higher. In this case, however, immediate action is not required and therefore we disagree with the severe violation penalty suggested by the drafting team. We suggest that the penalty for not investigating an operation timely should only qualify for a moderate VSL given immediate (within 1 hour or 1 day) activity is not required. We feel investigation of all operations and determination and implementation of correction misoperations is important to the long-term reliability of the BES. However, the system should be designed with redundancies to resolve any short-term issues and this Standard, while important, is designed to ensure long-term protection. Furthermore, we are not aware of any company who feels that the violation severity level determines whether they comply or not. Our organization strives to comply with all Standards with no violations, regardless of the violation severity level.
Yes
Group
ISO RTO Council Standards Review Committee
Charles Yeung
Yes
Yes
There is a lack of clarity on which entity is responsible for developing and implementing a CAP. We agree with the revision to Requirement R1, but believe that there needs to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible, expecially in view of the rationale provided in the text box for R1, whose excerpt says: “The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”. We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest to revise the leading part of R2 to: “Each Transmission Owner, Generator Owner, or

Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying….”. The Same revision should apply to R3, as follows: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of of the associated BES interrupting device operation,…..” Further, though not explicitly stated, we assume that the owner of the component that contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.
No
As we noted in our comments in the previous draft, the VSLs should recognize that some relay misoperations place a greater risk/impact on the BES than others.
Yes
Individual
Kayleigh Wilkerson
Lincoln Electric System
MRO NSRF
No
Although supportive of the proposed revisions to the definition of Misoperation, LES is concerned that the phrase “slower than intended” within the definition of a “Slow Trip – During Fault” may lead to unnecessary administrative work in an effort to prove what is considered an acceptable operation time for each Protection System. To avoid requiring entities to develop documentation stating “how fast is fast enough”, recommend modifying the Application Guidelines as follows: (3) …The phrase “slower than intended” means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate. [The intent is not to require documentation of adequate Protection System operation times, but to assure consideration by the owner(s) reviewing each Protection System operation.]
No
LES recommends additional clarification be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
Yes
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
No
ATC believes that the investigation for relay misoperation should be performed by the owner of the initiating relay as opposed to the interrupting device owner for the following reasons: • By definition, “Circuit breaker and other interrupting device mechanisms are not part of a Protection System”. As such, PRC-004 should not require the interrupting device owner to be responsible for R1. • PRC-004 is

based on Protection System operation, not breaker operation. • Bus design can have multiple breakers owned by different entities but the ownership of the initiating relay is clear. • The BES interrupting device owner lacks the information that the protective relay owner has to be able to perform a root cause analysis of a misoperation.
Yes
Group
seattle city light
paul haase
Yes
Yes
Yes
Yes
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the ICP include specifications that the entity identify mitigating factors performed under the CAP that specifically address the Misoperation.
Individual
Jack Stamper
Clark Public Utilities
Agree
Sacremento Municipal Utility District
Individual
Melissa Kurtz
US Army Corps of Engineers
Agree
MRO NSRF
Individual
Bill Middaugh
Tri-State G&T
Yes
Yes
Yes
The first instance of the abbreviation, DME, is undefined in M1 on page 7. It is defined as Disturbance Monitoring Equipment on page 19 in the Guidelines and Technical Basis section for R1. The definition should be moved to page 7.
No
None

Individual
Dale Fredrickson
Wisconsin Electric Power Company
Yes
No
It is not appropriate to make the owner of the interrupting device responsible to investigate Protection System operations. Interrupting devices as such are not components of a Protection System as defined by NERC. Responsibility for this investigation should be solely with the owner of the Protection System initiating the operation, and/or the owner of the Protection System which failed to operate.
No
Since owners of BES Protection Systems will be required by this standard to review all operations, it would be helpful to define the term "Protection System operation", at least as it is used in this standard.
Individual
Joseph DePoorter
Madison Gas and Electric Company
Yes
No
Please see question 5.
No
Under R4 there is confusion when the words "complete" is used. It should be stated (here and in the requirement) that an entity can extend the 180 days to complete if they have supporting documentation, i.e., parts on order, work orders, etc.
: As written in R1.1, if a BES generator's normal shut down cycle is caused by a Protection System operation (a set trip point in the relay) then each shut down would be required to be "identified and reviewed". This is similar to issues that a generator operator has under Project 2011-INT-02 AVR control during start up and shut down. MGE recommends that either a footnote be provided to address the exclusion of normal shut down processes or add another bullet excluding a generators normal shut down processes where the unit's breaker is activated via a set point within the Protection System (i.e., relay). R4 could be viewed as allowing for CAPs to be extended beyond 180 days (the maximum days in the combonation of R1 and R2). If this is the intent of the SDT, then clearly state this within the requirement. As written, an entity could be in violation of the maximum time frame of 180 days by extending the CAP under R4.
Individual
John Bee
Exelon Corporation and it's affiliates
Yes
Yes
Yes
The following changes are suggested: R1 – Add a Lower VSL condition that states, "The responsible entitiy failed to identify and review at least 2% or 2 (whichever is greater) Protection System

operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Add a Moderate VSL condition that states, "The responsible entitiy failed to identify and review at leastr 3% or 3 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Add a High VSL condition that states, "The responsible entitiy failed to identify and review at least 4% or 4 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Modify the 2nd Severe VSL condition with, "The responsible entitiy failed to identify and review at least 5% or 5 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Eliminate the 2nd Lower VSL condition all together because it is redundant with the 1st Severe VSL condition that addresses performing the actions in accordance with Requirement R1, Parts 1.1 and 1.2 in more than 170 days. R2 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R3 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R4 – Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed.
Yes
Exelon would like additional clarification added to the Application Guide regarding the inclusion of CAP corrective actions for addressing the application of the CAP to other Protection Systems owned by the utility. Specifically, the Guide should address that such a CAP can be considered complete once a program (required to address application of the CAP to other Protection Systems) is developed. Example 2 in the Application Guide exemplifies this notion. Additionally, application of the CAP to other Protection Systems owned by the utility should be considered fulfilled if an existing program (such as Protection System maintenance and testing practices) fulfill the actions necessary to address such a CAP.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
No
We would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn't have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips. Depending upon the guidance requested in the SPP comments (what will be required to prove that all faults have been analyzed) the time frames may become difficult to maintain especially during storm seasons. Likewise, the 60 days required to develop a corrective action once the cause is determined could become difficult for severe or extreme events. In extreme cases dynamic power flow models may need to be developed and applied to system studies before the CAP can be developed.
Group
Pepco Holdings Inc & Affiliates
David Thorne
Yes
No

Requirement R1 places the responsibility on the BES interrupting device owner to investigate all operations initiated by a Protection System which trips the interrupting device. We vigorously disagree with this assignment of responsibility. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the tripping of the interrupting device, not the owner of the interrupting device. All previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. Therefore, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device. The entity who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO's breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for reviewing and identifying all GO protection initiated trips just because the TO owns the interrupting device. This is totally unreasonable. In a power plant, when a generator unit trips off line due to a plant Protective System operation lockout relays are employed to prevent re-energization of the unit until the cause of the trip can be determined. When this occurs, the investigation of this event should be initiated and pursued solely by the GO (i.e. the owner of the protective system that caused the tripping of the BES interrupting device) and not by the TO, who may happen to own the interrupting device. The GO may request data and information from the TO to assist in their investigation, however, all compliance responsibility for reviewing operations and identifying misoperations should solely rest on the owners of the Protective System(s) that initiated the trip of the BES facility (in this case the GO). In this case, involving the TO solely because they are the owner of the interrupting device places an unwarranted compliance burden on the TO. Although the TO may be aware that the interrupting device opened, they are not is a position to determine if it was opened due to a plant Protective System operation, or was opened due to a manually initiated trip of the unit as it was being taken offline, since the GO, rather than the TO, usually has operational control over these breakers. In order to properly assign compliance responsibility to the appropriate entities, and eliminate the unwarranted compliance obligation on the interrupting device owner, we would suggest re-wording R1 in either one of two ways: OPTION 1 - Preferred: (assign responsibility to each Protection System owner rather than to the interrupting device owner) R1.1 "Within 120 calendar days of the operation of an interrupting device(s) which interrupts a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which is connected to trip the interrupting device(s) shall review the event to determine if their Protection System operation was correct, or a misoperation." With the above language the responsibility is clearly and properly assigned to the owner(s) of the Protective System(s) which initiated the tripping. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. While retaining this approach for shared Protection Systems the remaining Parts of Requirement R1 will also need to be re-worded to remove references to the interrupting device owner. OPTION 2 - Alternate: (replace owner of the interrupting device with owner of the interrupted BES Facility) R1.1 "Within 120 calendar days of the interruption of a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, the Transmission Owner, Generator Owner, and Distribution Provider, who owns the Facility that was interrupted shall identify and review each Protective System operation. If the entity owns both the BES Facility and the Protective System, determine if it was a correct operation, or a Misoperation. If the entity owns the BES Facility but does not own all of the Protective System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protective System component(s) and provide any requested investigative information. The Protective System component owner(s) that was notified by the Facility owner shall determine if there was a correct operation or a Misoperation of their component. 1.2 Within the same 120 day period of the

interruption of a BES Facility caused by a Protective System operation, the owner of the Protective System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified." The above language is consistent with the way TADS and GADS data is entered (i.e. by the Facility Owners). In addition, the Protective System(s) which protect and trip a specific Facility are almost entirely owned by the owners of the Facility. This Option adequately addresses the example raised previously, eliminating the need to involve the TO for generator initiated trips. The only complication arises when dealing with transmission lines terminating between two separate companies. The line terminals at each end may be owned by each respective company but the line itself may be entirely owned by only one company. To overcome this deficiency, this proposed re-write of R1 uses the term "line terminal" in the parenthetical list of BES Facilities. This would make the owners of the Protective Systems on each respective line terminal responsible for the review and analysis of their systems rather than the owner of the line itself.
No
Measure M1 requires evidence "that documents the date and time of each applicable interrupting device operation and indicates when each related Protective System Operation was reviewed." Based on our comments from Question 2 and proposed re-wording of Requirement R1, Measure M1 should also be revised to require evidence "that documents the date and time that each BES Facility was interrupted due to the operation of a Protection System and the date the Protection System operation was reviewed."
Yes
On page 18 of the Guidelines and Technical Basis section it states "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System Operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation." Furthermore, on page 19 it states "Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation …" Based on the arguments presented in our response to Question 2 we vigorously disagree with this assertion. When a Protective System operates, a means is provided to determine which protective component initiated the trip (i.e., relay targets, lockout relay operations, microprocessor relay event logs, etc.) The owners of these Protective System devices, which initiated the trip of the interruption device, are much better suited to investigate the cause of the Protective System operation than the owners of the interrupting device. In addition, all previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. In conclusion, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device.
To avoid confusion, Requirements R2, R3, and R4 should be re-worded to make it clear that they apply only to those entities whose Protective System misoperated and not to the interrupting device owner. The following language is suggested: R2. "Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall within 60 calendar days of identifying the cause of each Misoperation…" R3. "Each Transmission Owner, Generation Owner, or Distribution Provider shall, within 180 calendar days of the interruption of the BES Facility due to a Protective System Misoperation, complete for each Misoperation without an identified cause…." R4. "Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall implement each CAP or action plan, and revise as needed through completion."
Group
City of Tacoma, Tacoma Public Utilities

Chang Choi
Yes
Is mechanical failure of an interrupting device during a fault a mis-operation? (The interrupting device is not part of the Protection System.) Is inappropriate operation of a relay that operates upon mechanical inputs a mis-operation? For example, what if the relay causes a trip when it should have restrained?
Yes
Yes
No
Comments: Is it the intention of the PSM SDT that this version of the standard would require that all BES interrupting device operations be logged (documented) with a determination of whether the operation was caused by a Protection System? While it appears to be the intent of the draft revised standard that all interrupting device operations be reviewed at some level to determine if a Protection System caused the operation, it is unclear whether explicit documentation of each interrupting device operation must be generated and retained for purposes of compliance with PRC-004-3.
Individual
Mike Hirst
Cogentrix Energy Power Management, LLC
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once.
No
See comments to question 2
Yes

The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements?
Individual
NICOLE BUCKMAN
Atlantic City Electric Company
Agree
Pepco Holdings Inc and Affiliates
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
No
See response under Question #5 with specific recommendations to implement Internal Controls.
No
The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
No
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Individual
Jim Cyrulewski
JDRJC Associates LLC
Agree
Midwest ISO
Individual
Thad Ness
American Electric Power
No
AEP recommends removing the reference to "TPL standards" from the "Slow Trip - During Fault" category of the definition. AEP believes the intent of the "TPL standards" reference can be maintained

by capturing all slow trip events that result in clearing more Elements than necessary. AEP's first preference is to reword the category as follows "Slow Trip - During Fault - An Element's composite Protection System operation that, due to the duration of the composite Protection System's operating time, resulted in the clearing of other Elements in addition to the Faulted Element.". AEP's second preference is "Slow Trip - During Fault - A composite Protection System operation for the Faulted Element it was designed to protect which was slower than intended. Delayed Fault Clearing due to the non-operation of an installed high-speed protection scheme is not a Misoperation provided the duration of the composite Protection System's operating time did not result in instability or cascading, and did not result in miscoordination with any other composite Protection Systems." AEP recommends adding to both “Failure to Trip - During Fault” and “Failure to Trip – other than Fault” - “Please see Category 3(4) to determine if the “slow trip” classification applies to the operation.”
No
AEP recommends the following modification to 1.1: "Within 120 calendar days of a BES interrupting device operation in its Facility caused by a BES Protection system operation or by manual intervention due to a BES Protection System failure to trip, identify and review each BES Protection System operation and BES Protection System failure to trip.” AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs near the end of the 120 day period, and the notified entity does not have sufficient time to determine if their component operated properly or misoperated within the 120 day period. AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs more than 180 days after the BES interrupting device operation. AEP requests that R1 should be modified to clearly indicate whether the term “entity” includes separate Functional Entities within the same Registered Entity. As written, it is unclear if the Transmission Owner function is required to notify the Generator Owner function within the same Registered Entity for compliance with R1.1 Bullet 2 or if the Registered Entity with multiple Functional Entities is treated as a single unit for ownership purposes. R1.2 appears to add little value as a standalone requirement. AEP recommends removing R1.2. and incorporating the requirement to identify a cause within the remaining R1 and R3 wording.
No
AEP recommends adjusting the time requirements specified in the VSL tables for R1, R2 and R3 to extend the timeframe for Moderate and High VSLs to 20 days, and eliminate the time requirement for the Severe VSL. Example: For R1, the Low VSL remains the same, Moderate becomes >150 to 170, High becomes >170 to 190, and Severe only applies when “The responsible entity failed to identify and review… “. Measure M1 repeatedly lists the same evidence examples and AEP suggests simplifying the measure by stating “evidence for R1 may include but is not limited to….” followed by a single list of items. The wording for the R4 VSL references failure to revise a CAP “as needed”. This statement is very broad, may be subject to interpretation and should be clarified or removed from the VSL.
No
AEP recommends adding "remote backup relaying is not considered to be part of the composite Protection System" to the end of the description for the composite Protection System in the Application Guidelines. AEP requests that SDT include a clarification of the meaning of "BES interrupting device" within the context of this standard (similar to how "composite Protection System" is addressed). AEP recommends replacing both instances of the word "implementation" with "development" in the second paragraph of page 20 of the clean version of the standard. Otherwise it is implied that there are situations where a CAP must be fully implemented within 180 days. Please include a clarification of the CAP and action plan modification tracking. For example, if a CAP or action plan is modified, is it sufficient to document the modifications, or must the date the modifications were made also be tracked? On page 15 of the clean version of the standard AEP recommends adding “unintentional” before “loss of field” in the first paragraph. On page 15 of the clean version of the standard AEP recommends replacing “shut down” in the second paragraph with “as intended to isolate.” AEP recommends adding generation examples of both a normal time delay operation and a misoperation to category 3 of the application guidelines.
In the Rationale for R2 box, a reference is made to R4. This appears to be a typo and should be changed to R3. Since an evaluation is not part of the Corrective Action Plan definition, please make the following modification to the first bullet of R2: " Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and also an evaluation of the Action Items applicability to the entity’s Protection Systems at other locations, or..” AEP recommends revising R2, R3, and R4 to

specify that only the owner(s) of the Protection System component(s) that misoperated are responsible for applicable requirements. Measure 2 should be revised to remove the statement “explaining why there is no need to develop a CAP.” This is consistent with Measure 3. Declaration is described elsewhere in the standard. The Standard may read more clearly if the existing R2 and R3 were switched such that the requirement to develop a CAP (R2) came *after* the requirement to identify a cause or develop an action plan (R3) to complete further investigation. The phrase "composite Protection System", which is described in the Application Guidelines section, is not used in the Requirements, Measures, or Compliance sections. AEP requests "Protection System" to be replaced with "composite Protection System" where appropriate throughout the standard.
Group
Dominion
Mike Garton
No
The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
Yes
No
The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
: Suggest the Implementation Plan be modified under the Applicaibility section as indicated below: This standard applies to the following Facilities: Protection Systems for BES Elements. Underfrequency Load Shedding (UFLS) that trips a BES Element This standard does not apply to the following Facilities: The flowing Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) Non-protective functions that may be imbedded within a Protection System Suggest the Mapping Document be modified under the Proposed Language in PRC-004-3 column as indicated below: 4.2.1 Protection Systems for BES Facilities, Facilities needs to be replaced with Elements.
Individual
Anthony Jablonski
ReliabilityFirst
No
The revision to part three of the definition that converted the original parenthetical example into an exclusion by stating it inversely creates a potential loophole. The revised wording would consider correct the slow operation of a Protection System that caused avoidable equipment damage (due to the delayed fault clearing) as long as it did not cause a dynamic stability or coordination issue. The Protection System also needs to coordinate with the damage curves of the equipment within its zone. As the exclusionary sentence stands, it actually uses double negatives. It would be better to restate the sentence positively. A suggested improvement would to replace the second sentence in part three of the definition with the following: Delayed Fault clearing associated with an installed high-speed protection scheme is an example of a Misoperation if high-speed performance is required to meet the dynamic stability performance of the TPL standards or is required to ensure coordination with other Protection Systems.
No
Requirement R1 relies on the operation of an interrupting device and the identification by its owner that a Protection System operated and further that it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard. 1) First, the owner

of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. This partly is because the interrupting device excluding its trip coils and CTs is not part of the Protection System. The owner of the relay that activated the trip or the owner of the associated Disturbance Monitoring Equipment would be in a much better position to evaluate the operation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process. 2) Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it. 3) Finally, the requirement should be rewritten to obligate the owner of its Protection Systems to investigate their performance and to notify joint owners of their findings if they need to take follow up actions. Inserting the interrupting device owner unnecessarily into the process of investigation does not serve a reliability purpose but an administrative one.
Yes
No
Although this draft of the standard is considered a Results-Based Standard it is difficult to see how the requirements are written to achieve a measurable outcome associated with reaching a level of reliability performance, a reduction in reliability risk or a necessary level of competency. This draft standard instead appears to be administrative in nature that is more concerned with creating documentation solely for compliance purposes. The following are specific issues or suggestions: 1) the standard contains extra 120 day and 60 day deadlines that do not provide reliability benefit. Although there is value in investigating Misoperations quickly, it is more important to fix the problem and prevent its reoccurrence. 2) Late identification of Misoperations will be a violation even if they are not particularly significant. Specifically, Misoperations that occur with no Fault present may not be readily apparent. The deadlines in the standard could cause disincentives to fully investigate Protection System performance because it may result in compliance violations. 3) The standard provides no means of ensuring that Misoperations are addressed by CAPs on a timely basis. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause for this type of Misoperation should be either mitigated or the CAP completed in less 12 months. 4) It is suggested that the drafting team embrace a reliability performance based approach that would fit into the results-based philosophy. Specifically, adherence to the standard should be based on achieving or surpassing certain metrics such as Misoperation rate, the percent of causes unidentified (Unknowns/All in a year) and the percentage of open CAPs (Open CAPS/Misoperations in a year). These metrics are meant only as potential examples for measuring performance. By requiring certain levels of performance or continuous improvement in these metrics, then the goal of the standard can be met without the administrative burden of tracking relatively unimportant dates such as when a cause was identified or when a CAP was developed and the storage of large volumes of evidence records.
Individual
Mary Downey
City of Redding
Agree
BANC/SMUD
Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes

Yes
No
Only a request that the application guidelines be maintained with the final version of the standard.
Individual
Bill Fowler
City of Tallahassee
No
Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.
No
There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation.
No
Individual
Scott Berry
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency and has a couple of additional comments. Since the comment document is not formatted for this purpose, we will submit them here. The standard is titled Protection System Misoperation Identification and Correction, not Operation Identification and Submittal. IMPA does see that an organzation might keep track of operations but to require this action by a standard requirement and then potentially find an enitity in non-compliance is over reaching for this Protection System Misoperation standard. In order to be in compliant with this stadnard, an entity should only be required to perform the action of Protection System Misoperation Identification and Correction which is the standard title. Another problematic area involves the "same 120 day period of a BES interrupting device operation caused by a Protection System operation". What happens if the owner of the Protection System component is notified toward the end of the 120 day period of a BES interrupting device operation (say 119 day) and there is not sufficient time for an investigation by the Protection System owner into the cause of the trip? The Protection System owner should not be found non-compliant for requirement 1.2 if not enough time is given to them to properly investigate the reason for the operation of the Protection System.
Group
Tennessee Valley Authority
Brandy Spraker
No

The proposed Misoperation definition is based on the “Protection System” definition defined in the NERC Glossary of Terms (GoT). However, the NERC GoT does not provide the elements that are considered “Protective System” elements. The actual descriptions of the “Protection System” elements are found in PRC-005-2, 4.2 Faciliities. Recommend this PRC-004-3 revision include a new GoT definition of “Protective System Element” based on PRC-005-2, 4.2, Facilities, or a revision to the NERC GoT to include an abbreviated summary of the PRC-005, 4.2, Facilities in the “Protection System” definition; or include an abbreviated summary of the PRC-005-2, 4.2 Facilities into the PRC-004-3 definition of “Misoperations;” or revise both the NER GoT definition of “Protection System”, and PRC-004-3 definition of “Misoperation” to reference PRC-005, 4.2, Facilities, as the elements that are “Protection System elements.”
No
The changed wording of R1 was an improvement. However, our concern comes from our company enduring a major natural disaster and the aftermath. When recovering from a major event such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes weeks and is not the top priority for a utility that endures such an event. The Standard needs wording to allow additional time when a utility endures a natural disaster.
No
As per Req. 2 - CAP Devlopment is too stringent. Troubleshooting and determining which element could take longer than the time allowed in the VSLs. Under PRC-004-1 a 12 month time period was given to develop and implement a CAP. Recommend a CAP not developed w/in 120 days or a declaration in accordance with Req. R3 (Lower VSL), CAP not developed w/in 120 days or a declaration in accordance with Req. R3 w/in 120 days or CAP declared in accordance with Req. R2 not implemented within 150 days (Medium VSL), CAP not developed w/in 150 days or a declaration in accordance with Req. R3 w/in 150 days or CAP declared in accordance with Req. R2 not implemented w/in 180 days (High VSL), CAP not developed w/in 180 days or a declaration in accordance with Req. R3 w/in 180 days or CAP declared in accordance with Req. R2 not implemented w/in 210 days.
No
The PRC-004-3 requirements’ rationale for each requirement (gray boxes next to each requirement) and the Guidelines and Technical Basis (at the end of the document) are well thought out and contain significant justification and logic for each standard requirement. Recommend either keeping this information attached to the standard or formalizing it into a reference document that will will be easily accessible to the electric power industry. There was no indication in the draft standard as to the repository of this significant information.
Group
Duke Energy
Greg Rowland
No
The revised definition still contains the incorrect reference to TPL standards in “Slow Trip – During Fault”. The TPL standards Category A, B and C do not require Planning to identify every place where high speed protection is required for dynamic stability. If a Category B issue is identified, high speed protection is installed and it is no longer on the Category B list. If a Category C issue is identified, a redundant relay scheme is installed and it is no longer a Category C issue. Therefore, the list of places where “high-speed performance has been identified to meet the dynamic stability performance requirements of the TPL standards” is just a list of where the appropriate corrective action has not yet been implemented and could, in theory, be empty. “Slow Trip – During Fault” should be revised as follows: “A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified as needed by the Planning Authority or the Transmission Operator, or if it is not required to ensure coordination with other Protection Systems.”
Yes

Yes
Yes
See our comment above on Question #1. The following paragraph should be deleted from the accompanying Guidelines and Technical Basis section: “The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability . The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.”
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
No
Agree with the other changes but VSL severity levels are spaced 10 days apart. It should be at least 30 days apart. It is not justifiable to go from Lower to Sever VSL for 22 days of delay (149 days to 171 days). There is no justification for such strict time lines.
No
Individual
Don Jones
Texas Reliability Entity
No
The SDT may want to consider adding loadability as an example under “Failure to Trip – Other Than Fault” and under “Unnecessary Trip – Other Than Fault”. The existing definition of the ‘Slow Trip-During Fault’ needs to include that the delayed fault clearing associated with the installed high-speed performance of the protection system is not required to meet the voltage ride-through capabilities of the generators. Generators should not be tripping off line due to suppressed voltage in the system stemming from the delayed fault clearing. This could create steady state voltage issues. Suggested language: "Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems ***or result in loss of generation due to delayed fault clearing time***." Also, the definition of “Slow Trip – During Fault” refers to stability performance requirements of the TPL Standards, however, the TPL Standards do not cover delayed three-phase fault clearing studies. Delayed three-phase fault clearing can create undesired system conditions.
No
See comments submitted in response to Question 5 below.
Yes
No
The first paragraph of the Guidelines and Technical Basis defines the composite protection system to include the backup protection. This needs to be clearly defined as “local backup” only and not to

include remote backup protection.
We are concerned that the applicability of the Standard limits the misoperation analysis only to BES Element Protection Systems. Under the new BES definition and guidance documents, there will be numerous examples of misoperations on non-BES Element Protection Systems which could have a major impact on the BES when the fault must be cleared by remote backup relays. Example: Consider a 50MVA generator connected to a substation via a radial line. Under the new BES guidance, the generator is part of the BES while the interconnecting radial line would not be part of the BES under exclusion E1(b). If a fault occurs on the non-BES radial line and the Protection System fails to trip, the fault must then be cleared by either local or remote backup relays at the interconnecting substation(s). Under this scenario with the current proposed PRC-004 requirements, the owner of the non-BES radial line has no obligation to analyze or correct the Misoperation. The PRC-027 SDT received comments with similar concerns in its last revision. They have drafted language to ensure that coordination of non-BES Protection Systems between different Functional Entities. The PRC-004 SDT may want to consider similar language to ensure that all Misoperations which can affect the reliable operation of the BES are analyzed and corrected.
Group
Operational Compliance
Ed Croft
Yes
Yes
Yes
No
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
1) Please revise the Slow Trip – During Fault second sentence for clarity. We suggest: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation unless the high-speed performance has either been identified to meet the dynamic stability performance requirements of the TPL standards, or is required to ensure coordination with other Protection Systems.” 2) We suggest clarifying Definition (6) by replacing "is unrelated to on-site" with "the Protection System that operated is not directly associated with" as shown below to be consistent with page 17, and to exclude transfer trip testing: Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the Protection System that operated is not directly associated with maintenance, testing, inspection, construction or commissioning activities. 3) Add an Application Guideline example showing that transfer trip testing would not be considered Misoperation as well. Even though the BES interrupting device is at a different location than the testing error, the transfer trip composite system is involved. We suggest: "An operation that occurs during a non-fault condition but was initiated by remote transfer trip system maintenance, testing, inspection, construction or commissioning activities is not a Misoperation."
Yes
none
Yes
none
Yes

1) Unknown / unexplainable is the ‘cause’ of about 12% of Misoperations per NERC reports. An R3 ‘no further action’ declaration example would be helpful. Perhaps your ‘no action plan’ declaration example on page 23 was intended for this. If so, please so state there. 2) Please replace ‘reverse power’ with ‘overexcitation’ on page 15 in the failure to operate for a non-fault condition section. Reverse power relays are usually excluded so the example is confusing as is.
1) Some entities presently use their PRC-004 reporting as a means of documenting CAPs. They may prefer to use your proposed data request under Section 1600 of the NERC Rules of Procedure for these purposes. Please change page 5 wording to “The data submitted as part of the data request will not be used by NERC or the Regions for compliance or enforcement purposes.” 2) Compliance section 1.2 on page 9 states “The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.” Please delete “and Measures M1, M2, M3, and M4” because entities must comply with Requirements, but Measures are not allowed to expand that scope. 3) In the first sentence of R2 on page 7, please add “first” before “cause” so it reads “Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the first cause of each Misoperation: …” Pages 19 and 20 make it clear that this is triggered by the first cause, but some entities may miss this application guidance. 4) Please include ‘Composite Protection System’ as a defined term that remains with this standard (similar to PRC-005-2 approach for Component, Component Type, etc.). Your definition on page 14 is fine, but move it up to just after the page 3 Definitions. Regarding commments for all questions 1-5 above: 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
Wryan Feil
Northeast Utilities
Yes
No
R1.1 second bulleted item states: If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. This requirement statement is confusing and should be revised to clearly describe the intent. Additionally, this statement requires action by more than one entity within the 120 day time period. There is no requirement for BES interrupting device owner to notify the owner of the protection system component identified as contributing to the misoperation prior to 120 days which could leave the protection system component owner no time to investigate and determine if the operation was correct or not as required in R1.1 and determine the cause as required in R1.2 (which also must be completed within the first 120 days). We suggest that the above statement be a separate requirement under R1 and be worded as follows: If the BES interrupting device owner cannot determine that the Protection System operation was correct, and concludes that protection system components owned by another entity contributed to a possible misoperation, the BES interrupting device owner shall notify the other owner(s) of the Protection System component(s) of their preliminary conclusions and provide any requested investigative information within 90 days of an interrupting device operation. It is suggested that a 90 day timeframe for this situation is still reasonable for the interrupting device owner and allows 30 days for the owner(s) of the Protection System component(s) to comply with the existing R1.1 and R1.2. During the 120 day review period, requirement 1.1 does not ensure that there will be adequate time for ALL Protection System owners to review the operation. If the BES interrupting device owner is tardy in informing another Protection System component owner, then that Protection System owner may not have time to perform a review. There should be some milestone within the 120 day review period where all Protection System owners need to be informed of the operation and their need to review it.

No
We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
No
Individual
Jonathan Appelbaum
The United Illuminating Company
Agree
Northeast Power Coordinating Council (NPCC)
Individual
Mark Yerger
Pepco Holdings, Inc Segment 1
Agree
Pepco Holdings Inc and Affiliates, Segment 1
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
Suggest Misoperation definition #6 be revised from “unrelated to on-site maintenance….” to “unrelated to maintenance….” to clearly allow as an exclusion, a Protection System maintenance or commissioning activity which results in an inadvertent remote end station trip. For example, a direct transfer trip scheme.
Yes
Since actual Misoperation data reporting will now be addressed outside of this standard, entity data communication requirements within this standard need to be consistent with respect to data reporting criteria. As an example, since there is no requirement for a contributing component entity owner to forward the required investigative and CAP data to the interrupting device entity owner, one would expect that reporting will be the responsibility of the Protection System contributing component entity owner.
Yes
No
Suggest “Composite Protection System” as listed in the Guidelines and Technical Basis section (page 14 of 24) be a defined term for this standard.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration believes that the latest version of the definition correctly captures the intent that the action of the composite Protection System is the gating factor in the determination of a Misoperation. The aggregate action of the primary, secondary, and pilot systems should form the basis of the expected performance, not each individual group of components. However, we still believe that the project team’s intent to allow Protection System owners some flexibility to determine when a “slow trip” occurs is not captured. We fully agree with your statement in the last Consideration of Comments that it is up to the owners to have “an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm,

and ultimately be able to decide whether the speed or outcome of its Protection System was adequate.” However, unless the language is captured in the standard or the definition, CEAs may choose a different basis. In the extreme, they may determine that any delay outside the settings or manufacturer’s specifications to be a Misoperation – even if reliability is not threatened or monitoring equipment cannot resolve down to that level of granularity.
No
Ingleside Cogeneration agrees that the owner of the tripping device should own the investigation and bring in other entities as needed. In addition, R1 takes out any guesswork about the responsibilities of each Protection System owner who may have contributed to the Misoperation. What we still do not understand is the recourse available to the Protection System owner if the request for assistance from an adjacent entity is sent late. The requirement does not account for the fact that a notification may be issued weeks after the fact – the 180 day assessment deadline applies regardless. Under these circumstances, the recipient may be forced to declare that a cause was not found, as allowed by R3, and develop an action plan to investigate further. However, this leaves that owner in the position to explain the delay to auditors; which we do not believe is appropriate. Even more concerning, there appears to be nothing that stops the CEA from deciding that the reduced interval was adequate and assessing a violation as a result.
Yes
No
Ingleside Cogeneration shares the project team’s desire to retain a scholarly and cooperative approach to the assessment of Misoperations. However, we believe that the regulatory pressure will mount – particularly as NERC’s events analysis numbers continue to show Misoperations as a primary component in nearly every wide area outage. This means concepts that are implicitly understood today will be immaterial in the future. For example, it is easy to see that a CEA may assess a violation for a single missing relay operation evaluation out of hundreds that may have occurred during a wide-area weather event. Despite assurances that the CEA will take the circumstances “under consideration”, we are not convinced that that will always be the case. If the drafting team is reluctant to modify the definition of “Misoperation” or PRC-004-3’s requirements, there may be an opportunity to capture these understandings in a binding way in the RSAW. There is a new program that has been initiated by NERC to include Compliance representatives in the standards drafting process for situations just like these. If we are able to provide commentary on the auditors’ instructions captured in the RSAW, it would alleviate our doubts that understandings reached during the development phase would be retained when the standard becomes mandatory.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the response to our comments, but, we do not believe our issues have been resolved. First, on “Slow Trip”; however, we disagree with your perspective. The SDT is taking a relativistic approach to time, e.g., interpreting the words it drafted “slower than intended” as relating to whether the Protection System operated “fast enough to prevent additional harm” and not a more common interpretation of it operated slower than it was designed to operate. FMPA believes that an auditor would interpret this using the latter interpretation and instead ask for the design clearing time of the protection system as a comparison of whether actual operation was “slow”, e.g., if the system is designed to operate in 5 or 6 cycles and instead it operates in 7 or 8 cycles, fast enough to prevent backup protection from operating, but slower than designed, is that slow? If the SDT intends “slower than intended” to mean that it operates “fast enough to prevent any additional harm”, e.g., the clearing time of the back-up protection, then state that in the definition. The response to our comment (and the Application Guidelines) focuses on the owner of the Protection System “should have an understanding of the objectives of its Protection Systems”; that is not FMPA’s concern. FMPA’s concern is how an auditor will audit R1 and verify that the entity identified all misoperations, and how an auditor will interpret “slower than intended”. Second, FMPA commented last time

(commenting on R1) on the difficulty of measuring whether a fault actually occurred and where the fault in regards to the definitions of "Failure to Trip" and "Unnecesary Trip". For both, an auditable investigation would need to determine if: 1) a fault actually existed, which can be quite difficult to verify for something like a lighnting strike with automatic reclosing; and 2) where the fault was; so that it can be determined whether or not the fault was "within the zone it was designed to protect". In investigating tripping of BES Elements, a large number of those events are indeterminent, meaning that physical evidence could not be found. With microprocessor based protection systems, if may be possible to set up a sort of event recording function that may be able to provide evidence of fault condition and roughly where a fault was; however, with electromechanical relays, that is not possible without installing additional equipment. Is the SDT intending to require a form of event recording at each substation so that the existence and location of a fault can be determined for every protection system trip? If no evidence of a fault exists, would the default assumption be that everything operated as intended unless the evidence of protection system operation indicated otherwise (e.g., both primary and backup systems operated)? If that is the intent, then that intent should be stated within the requirements. Third, how would a high impedance fault be treated? Such a fault could occur within the relay reach, but, the impedance of the fault could in essence cause the fault to appear further away than it actually is. For instance, assume a line is protected by an instantaneous ground overcurrent relay protecting about 70% of the line and by an inverse time ground overcurrent relay as local backup. And let's say a high impedance fault occurs 50% of the length of the line, but the impedance of the fault reduced the fault current to below the instantaneous relay setting such that the inverse time ground overcurrent relay operates instead. Is that a misoperation because the instantaneous ground overcurrent relay failed to operate for a "Fault within the zone it was designed to protect"? Which leads to the ambiguity of the phrase "within the zone it was designed to protect". Does zone mean a distance as derived from the relay settings, or is it the relay settings themselves? If it is the relay settings themselves, then FMPA suggests changing the phrase to eliminate "zone" and instead refer to the actual protection system settings. Fourth, FMPA is also concerned about how "composite Protection Systems" works, especially with the combination of "within the zone it was designed to protect". For instance, let's assume Line 1 has typical stepped disctance scheme of zones, 1 through 3, and let's assume the adjacent Line 2 has a fault and there is a failed breaker at the intermediate substation. The breaker is not part of any protection system, but, the zone 3 remote backup relay of Line 1 operates to help clear the fault on Line 2, which is a correct operation. So, is Line 1's zone 3 relay part of Line 1's composite Protection System, and if so, then there is not a single "zone" for composite Protection Systems, which again adds to the ambiguity of the phrase "within the zone it is designed to protect". Fifth, some misoperations are due to mistakes made by protection engineers, e.g., mistakes in establishing relay settings; so does: "within the zone it was designed to protect" the actual design of the protection engineer, e.g., the mistaken relay setting, or what the design should have been? If the latter, how will the 'what the design should have been' be determined? If the SDT has not already done so, FMPA recommends involving NERC and RE enforcement staff to discuss how R1 would be audited in combination with these definitions.
No
First, as currently drafted, R1 means that each investigation into a protection system operation is auditable, which in turn means that the definition of misoperation as discussed in question 1 need to be easily measurable. Please see discussion in question 1 about the difficulty in measuring: 1) "slower than intended"; 2) whether or not a Fault occurred; and 3) whether or not that Fault was "within the zone it was designed to protect". Second, there are numerous Protection System operations wtihin a year, which results in a high-volume problem similar to those found in CIP standards, COM-003 and PRC-005. FMPA continues to recommend, as we did last time, that this standard would be better served by instituting internal controls language for R1 similar to what the CIP v5 and COM-003 SDTs adopted. Adopting such language would have the additional benefit of allowing the entity more latitude for how they deal with the ambiguities described in response to question 1. Third, FMPA commented last time that there ought to be an exception for Acts of Nature such as hurricanes and other natural disasters with, at minimum, the 120 day rule being waived. In response to FMPA's comments, the SDT agreed with this concern. However, rather than change the standard, the response was: "The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines

outlined in this standard." That means that the entity would still be in violation of the standard if it were not able to investigate all relay operations that occurred dueing a natural disaster. This is not acceptable to FMPA and we desire language to extend the time of the investigations as a result of Acts of Nature (e.g., a named storm, an earthquake that resulted in severe damage, etc. – maybe anytime a State's Governor declares an emergency) to a longer hodl th entity to the 120 day time period, e.g., but instead to a longer period such as 240 days, to allow time for more pressing disaster recovery efforts, without actually incurring multiple violations to the standard that would remain on the entities "record". Fourth, there is no recognition that it is possible to have a condition where it cannot be determined whether the operation was correct or a Misoperation, e.g., if the location of the fault cannot be determined, or whether a fault condition actually existed or not, especially for something like a trip with successful reclose. See the second point made in response to question 1 for further discussion.
First, R4 uses the phrase "as needed." In doing research for legal precedence interpreting the phase "as needed," both in terms of contract interpretation and statutory construction, numerous cases throughout the country make it clear that, unless this phrase is clearly defined in the context in which it is used, this phrase is ambiguous and will only lead to conflict. For instance, the phrase indicates that (1) there is a level of discretion involved regarding an action that must be taken, and (2) someone must make a determination as to when such action is deemed "needed." However, the standard is silent both as to what factors trigger the exercise of discretion and who makes the determination that a change to the CAP is "needed" - the entity or compliance staff. In this regard, FMPA recommends making it crystal clear what "as needed" means. For example, it could state "as needed to reflect any CAP revisions made by the responsible entity, as determined at the sole discretion of the responsible entity." Second, R4 should recognize that not every investigation of a Misoperation ends in a CAP, e.g., those where no cause was found in accordance with R3.
Individual
Brett Holland
Kansas City Power & Light
Yes
No
R1 and the rationale for R1 assume that the BES interrupting device owner and the Protection System owner have been talking and R1 requires identification and review of each operation within 120 days. R1 should require that the BES interrupting device owner notify the Protection System owner or vice versa, depending on which entity discovers the event first, within a specific time after the entity is aware of the operation in order to ensure that the other entity has adequate time within the 120 day period to finish the review.
No
R4 VSL wording is not clear as presently stated; "The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4." It might not be intended, however this wording implies that all CAP's must be revised and if not revised there is a compliance issue. The wording should state; "A CAP revision was needed in accordance with R4 and the responsible entity failed to make the revision."
Yes
There are some examples of CAP in the document. Adding examples relative to my comment in question 5 would be beneficial.
R2 requires a CAP except in cases where the entity can "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" R2 does not recognize that every CAP requires resources to complete and that the industry has limited resources. There are cases where the required resources to complete a CAP at multiple locations provides minimal increase in reliability. If these low productivity CAPs are required to be completed the net result is a decrease in BES reliability since other more productive work will not be done due to lack of resources. The entity should be able to state the CAP was completed at only the affected site and was not rolled out

system wide due to poor ratio of resources required to reliability benefit gained.
Individual
Daniel Duff
Liberty Electric Power LLC
No
I agree with the position of the Standards Development Team of the North American Generator Forum, which states: The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The "same 120 days" could place an impossible burden on an entity notified late in the 120 day period. Notification that an issue with an entity's system contributed to a misoperation should start a new compliance clock.
No
Agree with the comments of the Standards Development Team of the North American Generator Forum, which state: The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
The standard would be simplified by combining R1 through R4 to state: R1 For each activation of a BES interrupting device initiated by a Protection System, the entity shall identify the cause of the operation. R1.1 If the activation is determined to be a misoperation, the entity shall develop a corrective action plan, or explain in a declaration why a CAP cannot reasonably be instituted. R1.2 If no cause can be determined, the entity shall develop an action plan for further investigation, or explain in a declaration why no further action is warranted. R1.3 All action plans shall be developed within 180 days of the operation, or notification of an operation of a BES interrupting device caused by the RE's Protection System. R2 All action plans developed under R1 shall be implemented or revised as needed until complete. The additional detail in the current version (work timetables, other facilites) should be moved to the measures, as they are the output of the requirements.
Individual
Joylyn Faust
Consumers Energy
No
There still seems to be a contradiction in R1 regarding the responsibilities of the BES interrupting device owner (IDO) vs. the Protection System owner (PSO) when owned by different entities (as we commonly have on the 138 system). The breaker, other than the trip coils and CTs, is not part of the Protection System, so the responsibility to investigate operations initiated by a protection system should be with the PSO. NERC’s response below to Q4 seems to agree with this (regarding documenting, CAP, and reporting), but R1 still places responsibility for investigation on the IDO. As a matter of fact, the Rationale for R1 added into draft 3 the statement “Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection

System." When an interrupting device operates, logically the IDO would investigate why their device operated. As soon as the IDO finds out that the operation was initiated by a protection system (the situation described in R1) they should then only have to notify the PSO of the situation (the PSO may not be aware of a protection system operation). The IDO would not be in the best position to investigate, and should not be validating Protection System operations for the PSO. The seems to be mostly a contradiction of the wording in R1 vs. the Rationale section. If the Rationale is not included in the final version of the standard, I could probably agree with the wording of the rest of it.
Individual
Daniela Hammons
CenterPoint Energy
Yes
No
CenterPoint Energy is concerned the wording of R1.1 to review a BES interrupting device "operation" within 120 days and the wording of R1.2 to investigate a "misoperation" within the same 120 day period of a BES interrupting device operation could be unworkable. The owner of the BES interrupting device could notify the owner of the Protection System component identified as contributing to the Misoperation well into the 120 day period, which would give the Protection System component owner little time to investigate and determine a cause. CenterPoint Energy recommends R1.2 wording be the following: "The owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified, by the latter of 120 days of a BES interrupting device operation or 30 days after receiving notification from the owner of the BES interrupting device."
Individual
Kenn Backholm
Public Utility District No. 1 of Snohomish County
Yes
No
See response under Question #5 with specific recommendations to implement Internal Controls.
No
The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Group
ACES Standard Collaborators
Ben Engelby
No

(1) The term “composite” Protection System is unclear, used inconsistently and should be defined. Based on the first sentence on Page 14 of the Guidelines and Technical Basis section, it appears that all Protection Systems protecting an Element are intended to be included in composite Protection System. That is any primary, secondary, backup, pilot and non-pilot relay schemes for a given Element would be included in its composite Protection System. If this is the case, we suggest just writing a definition so it will be clear where the term comes from and what the meaning is. However, it is not clear that the term is even needed since the definition of Protection System would already include all of these Protection Systems. The definition includes “Protective relays which respond to electrical quantities.” The inconsistent use of “composite” in the standard documents only creates more questions for the need of the definition. For example, on page 14 of Guidelines and Technical Basis section under the section (1) title, the “overall performance of the Protection System for the Element it is designed to protect” is used. This is understood to be all “protective relays” including secondary, backup, pilot and non-pilot relay schemes. As defined, Protection System includes the plural use of protective relays so all could be included. (2) Why does the definition need an introductory sentence? The clarifying statement “any of the following is considered a Misoperation” provides the same outcome. Also, several of the sub-parts of the definition discuss the “overall performance of the Protection System,” so this introductory sentence seems redundant. Instead of adding confusion, we recommend that the drafting team strike the entire introduction sentence of the definition. (3) For sub-part “3. Slow Trip – During Fault” of the definition, we recommend revising the second sentence. It is a run-on sentence, uses incorrect grammar, contains a triple negative statement, and is confusing. We recommend revising the sentence to clearly state when delayed fault clearing should be excluded and what conditions must be met before the operation is not to be considered a Misoperation. For sub-part “5. Unnecessary Trip – During Fault” of the definition, we believe that the revised sentence now overlaps other sub-parts of the definition. “A Protection System operation for a Fault for which the Protection System is not intended to operate” is almost the exact definition of Misoperation in the introductory sentence. Nothing in this sub-part discusses an unnecessary trip. The phrase “not intended to operate” could apply to all of the other sub-parts because a failure to trip, slow trip, or unnecessary to trip would be the result of a Protection System not operating the way it was intended. More detail is needed for this sub-part.
No
(1) Also it is still unclear who has the ultimate responsibility for identifying and reviewing each operation if the interrupting device and Protection System are owned by two or more parties. What should occur if there is disagreement over the responsibility or the ownership of a component? What if multiple parties owned components that contributed to an operation or a Misoperation? Are both parties responsible? The rationale may provide additional guidance, but the words in the requirements are unclear. (2) “BES interrupting device” is not a defined term and is vague and ambiguous. We understand that devices that interrupt fault current, such as circuit breakers and circuit switchers would be included but what other devices such as motor operated disconnects? Are they not included because they don’t interrupt any current? What if they are equipped to interrupt charging and load current? Failure to define “BES interrupting device” could result in an informal definition that results in inconsistent enforcement by including components outside of the scope of what is intended to be a BES interrupting device. This term adds uncertainty and creates opportunities for multiple interpretations.
No
(1) The measures are not consistent with the revisions to the requirements. For instance, Requirement R1 requires the owner of the component that led to the Misoperation to identify and review its performance. However, the Measures require the applicable entities to have evidence without any statement regarding the ownership of Protection Systems or circuit breakers.
No
(1) If the drafting team intends to move forward with “composite Protection System,” we recommend adding it as a new proposed definition. After reading the technical guidelines, we are not persuaded that the drafting team has articulated the difference between a Protection System and a composite Protection System. A proposed glossary term would allow industry the opportunity to provide the feedback as to whether an additional term is needed in order to have the proper scope for identifying Misoperations.
(1) We recommend introducing the term “BES interrupting device” as a new definition with clearly defined parameters. (2) We would like more information on the Section 1600 data request for

Misoperation data. Also, if a data request is going to be utilized, will registered entities still need to continue reporting under PRC-004-2? This would be a redundant process and we encourage NERC to coordinate the timing of the data request to take the place of the current reporting requirements. Further, we disagree with the evidence retention section of this standard. TO, GO, and DP are audited on a six-year cycle, which is too long of a timeframe to retain evidence. We suggest shortening the amount of time to three years, unless there is an open or ongoing investigation, action plan, or CAP. If there is a section 1600 data request, why does the data need to be retained? NERC already has the information. (3) This standard is another candidate for implementing internal controls, and should not contain “zero-defect” language. For example, an entity should be able to have controls in place to determine whether Misoperations are being identified, assessed and corrected. This is the essence of PRC-004-3, and therefore should be revised to include these concepts. There should not be zero-defect penalties if an entity has controls to catch errors and fix them. Currently, the standard would penalize an entity for each instance of noncompliance. (4) We continue to be confused by the interaction of Requirements R1 and R3. While R1 does not compel the protective relay owner to identify the cause of a Misoperation, it does compel the owner to investigate the Misoperation. One would presume an auditor would expect investigative actions conducted for Requirement R1 to be reasonable. However the application guidelines section for Requirement R3 states clearly on page 14 that this requirement only applies if “reasonable investigative actions have not been exhausted”. Thus, it would appear that Requirement R3 could never apply without a violation of Requirement R1 Part 1.2. We think the interaction of these requirements need further clarification. Furthermore, we suggest that Requirement R3 could actually be made part of Requirement R1 which would help alleviate the confusion. For example, Part 1.2 could have a subpart that states that an action plan should be developed for any reasonable investigative actions that may require more than 120 days to complete. Another part could be to document why the cause cannot be identified. (5) Since UVLS is specifically excluded in the applicability section does it make sense to include it under voltage conditions in part 2 and 4 of the Misoperation definition? (6) Why can’t the implementation requirement R4 be included as a Part of the other requirements? Furthermore, it is questionable if it is even needed for FERC has stated in past orders that there is an implied obligation to implement plans, policies and procedures when a requirement compels their development. This requirement is similar to the types of standards that would be subject to Paragraph 81. (7) Thank you for the opportunity to comment.
Group
JEA
Tom McElhinney
We believe that the issues should be handled through modification of PRC003 not PRC004.
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Pepco Holdings Inc and Affiliates
Group
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes
Southern Company supports the SERC comments and are including the following additional comments: 1. We believe that the same consideration of whether or not the composite Protection

System operated as intended could be addressed with a much simpler definition: "The failure of the Protection System to operated as intended, including failing to trip when it should have, unnecessarily tripping with it should not have, or tripping more slowly than intended." This definition allows the Protection System owner to evaluate the operation and determine if it operated appropriately. 2. We believe that the shift in focus to "composite" and "overall performance" does not clarify the ability to identify misoperating Protection System components.
No
1. The requirement R1 can be simplfied by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. 2. The notification and response requirement of R1 is not needed, as the owner of the Protection System that operated is already required to investigate each operation in Requirement R1. An additional requirement for notifications and responses is superfluous. 3. There is a timing problem with R1.2 for the protection system owner who is notified on day 119 following a protection system operation. It is not reasonable or just to require this protetion sytem owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a misoperation of another entitiy's protection system.
No
1. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. 2. The severe VSL for R1, R2, and R3 can be simplified by changing a few words in the first item of each requirement. For R1, change "...entity performed the actions in ... and 1.2 in more than 170..." to "...entity did not perform the actions in .... and 1.2 within 170 ...". This would allow the 2nd and 3rd items in the OR statement to be eliminated. For R2, change "entity developed a CAP, or a declaration .... R2, more than 90 ..." to "entity did not develop a CAP or a declaration ...R2 within 90 ...". This would allow the second part of the OR statement to be eliminated. For R3, change "entity developed an action plan, or made a declaration ... R3, more than 230 ..." to "entity did not develop an action plan or make a declaration ... R3 within 230 ...". This would allow the second part of the OR statement to be eliminated. 3. The VSL should be have a weighting factor in the % of operations not analyzed (otherwise it is one strike and you're out and this could be one event out of many). Equal severity for 1/10 events is not just compared to 1/100 events.
Yes
Southern Company supports the SERC comments and are including the following additional comments: 1. In various locations of the text, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misopeartion rather than simply that they are not misoperations (we believe that they are still misoperations). We believe that entities should be allowed to determine whether or not the Protection System operated appropriately. This is inherent in our suggested simpler definition of Misoperation through including "than intended". 2. In the text for section 6 of the Misoperation definition, we disagree with the phrase "An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspetion, construction or commissioning is not a Misoperation." This is obviously an unnecessary trip - other than fault. This should be included in a list of non-reportable misoperations.
Southern Company supports the SERC comments and are including the following additional comments: 1. By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms as well as the term ‘action plan’ in R3, it is unclear what differences exist between a CAP and an “action plan” as written in PRC-004-3. Please modify language to be consistent or add language that describes the intent and difference between a CAP and an “action plan”. 2. R2 and R3 should be restructured such that it is immediately apparent that R2 deals with Misoperations with an identified cause and R3 deals with Misoperations without an identified cause. This could be accomplished by phasing that condition first in the requirement so that the required actions that are bulleted immediately follow the "shall" such as: "R2: For each Misoperation with an identified cause, the entity shall either develop a CAP ... or declare why ..." and "R3: For each Misoperation without an identifed cause, the entitiy shall either develop an action plan ... or declare why ..." 3. R4 should be re-structured to flow more smoothly, as follows; “R4. Each entity shall implement and revise, as needed, each CAP or action plan. 4. The three bullets found at the top of page 6 of draft 3 of the standard

should be the three requirements of this standard. Has any consideration of making those three items the actual requirements? 5. Please consider using the phrase "component that misoperated" rather than "component that contributed to the misoperation" in the standard for clarity. 6. There is too much unnecessary date bookkeeping in the Requirements. We recommend deleting all existing date clocks linked to each event and specify a resolution time limit for investigative action plans/CAPs to be the filing date deadline for each quarter. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability. The establishment of investigative action plans and/or completion of necessary Corrective Action Plans in a timely fashion are the actions which will affect the reliability of the Protection System. 7. In reference to the above comment, if the timeframe are to remain, the SDT is strongly encouraged to move toward an internal controls format for this standard.
Individual
David Jendras
Ameren
Yes
Yes
No
(1) We disagree with the VSL escalation, for R1, R2 and R3, from Moderate to High to Severe at 10 days interval each.
Yes
(1) Please clarify the sentence on page 17, the second to last paragraph, "Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations" by putting it in a new paragraph and including some examples. Does the protected Element have to be out of service? Is this intended to include human error (e.g. bumping the panel) caused trips by personnel other than Protection System maintenance personnel? (2) Please add "completed" on page 20, near the bottom, so that the title reads " The following are examples of completed Corrective Action Plans (CAPs):" (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.
Group
PPL NERC Registered Entities
Brent Ingebrigtson
No
The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: • The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. • Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. • The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). • Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
No
The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own…" by the required time frame. There is a possible time coordination issue for identification and review of misperations with R1.2. As stated in the proposed

standard, R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. If timely communication of misoperation information is delayed by a Protection System component owner, the BES interrupting device owner could possibly bear the responsibility of not meeting the 120 day reporting requirement per R1. Fundamentally, R1 frames the time period for reviewing and analyzing a misoperations where multiple responsible entities are involved. However, R1 does not take in to account that one entity's analysis may be dependent upon the other's final analysis and that parallel review of misoperations are not possible. More consideration should be given to the cases where one entity's actions impact another's ability to meet the requirements of R1. However, concur in overall concept with clarifying coordination roles between BES interrupting device owner and the Protection System owner.
No
The VSLs are hard-wired to response/reporting timelines specified per R1-R3. Some consideration should be given to technical complexity and circumstance of the SPS Misoperation. The R1 evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to …then list the items once.
Yes
The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
The PPL NERC Registered Entities (PPL Electric Utilities, PPL Generation LLC, PPL Energy Plus, LG&E and KU Services) are in agreement with the spirit of the North America Generator Forum Standards Review Team comments for the successive ballot for Project 2010-05.1 Protection Systems: Misoperations. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. The three bullets found at the top of page 6 of draft 3 of the standard are possibly sufficient requirements for this standard. Has any consideration been given to making those three items the actual requirements?
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No
No
No
The documentation requirements for maintaining a database of every operation of a BES interrupting device, which are laid out in Measure M1, represent a significant step change in documentation requirements when compared with the current misoperation analysis and reporting requirements. Unintentional mismanagement of a database that identifies every operation by time, date, and date of review during a six year audit window poses no significant risk to the reliabile operation of the Bulk Electric System. However, enforcement of this measure will likely identify clerical or other

unintentional errors made during the process of tracking misoperations that will impede NERC's ability to address violations that pose a moderate or severe threat to the reliability of the Bulk Electric System. The underlying objective of the data compiled in the measure appears to be a 'best practice' method for retaining data necessary to meet the quarterly reporting requirements for misoperation reporting; specifically reporting of the 'total number of operations'. While it is understood, that NERC is utilizing this quarterly reporting data to develop metrics to track the performance of BES Protective Systems, the required implementation of a prescriptive tracking method in a Reliability Standard does not balance the need and method for addressing the need, and compliance with the quarterly reporting of misoperation data is already driven by NERC's Rules of Procedure. The SDT should consider modifying Measure M1 in such a way that it requires misoperation analysis reports (Corrective Action Plans and Action Plans) to include the level of detail addressed in Measurement M1 (time & date of operation, date analysis determined it was a misoperation, etc.). This modification would address the need to ensure that misoperations are appropriately analyzed within a reasonable amount of time while avoiding the implementation of a Reliability Standard requirement that could create enforcement actions that hinder NERC's ability to address potential violations that pose a moderate or serious threat to the Bulk Electric System.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
Yes
Yes
No
ramping up the violation level simply on the number of days that pass to complete the analysis does not seep appropriate for situations where the discovery may have been delayed in the first place
Yes
Generally, the standard does not seem to address the reporint of no events now being required by the RE, especially for entities that have only a few devices, the reporting burden for non-events shoudl be clearly eliminated. It is not clear that it is eliminated. Only the reporting of actual misoperations should be required as defined.
Individual
Cole Brodine
Nebraska Public Power District
Yes
Yes
Yes
Yes
The drafting team should review the BES Definition drafting team documents and evaluated how it relates to misoperations. It would be desirable to avoid any disconnects or conflicts between these definitions and standards. Some BES Definition drafting team documents indicate individual wind turbine generators are part of the BES. Is misoperation data desired down to this level? During Webinars explaining the BES definition documentation questions were asked regarding how the BES documentation helps identify or determine what protection systems are included for PRC-005. The BES drafting team stated that protections systems for PRC-005 are not to be defined by the equipment identified in the BES definitions documentation but instead are to be defined the PRC-005 standard and documentation. Would this be the case for PRC-004-3 as well?

Individual
Kenneth A Goldsmith
Alliant Energy
Agree
MRO NSRF
Individual
Scott Langston
City of Tallahassee
No
Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault.
No
There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation.
No
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
Some of the scenerios for possible mis-operations are too vague. For example, what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation; however, it would still protect the equipment as it was designed. Also, it can be difficult at times to determine if a fault actually occurred within a relay's zone of reach. If a bolt of lightning causes a fault on a line, unless there is physical damage, there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you cannot first confirm what caused the fault.
No
There should be some provision in the standard to take into account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. Also, there are some circumstances when an investigation is out of the control of the entity. For example, if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company, it may take longer than 120 days to perform a thorough investigation.
No

Individual
Bob Thomas
Illinois Municipal Electric Agency
Agree
Florida Municipal Power Agency
Individual
Michael Falvo
Independent Electricity System Operator
No
NPCC uses different terms, such as failure to operate (not operating when required) vs misoperation (operating when not required). We think that the definition here has the intention of defining more generally an "incorrect operation", and perhaps the "incorrect operation" should be used for both different terms.
No
1 We belive that R1 should be written more clearly, by saying that: “Within 120 calendar days of a BES interrupting device operation casued by a Protection System operation, each Transmission Owner, Generator Owner, or Distribution Provider - that owns the BES interrupting device - shall identify and review each Protection System Operation.” 2 Also, there is a lack of clarity on which entity is responsible for developing and implementing a Corrective Action Plan. We believe that there has to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible for the CAP, especially in view of the rationale provided in the text box for R1, whose excerpt says: “The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”. We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest revising the leading part of R2 to: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying….”. The Same revision should apply to R3, as follows: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of the associated BES interrupting device operation,…..” Further, though not explicitly stated, we assume that the owner of the component that contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.
Yes
Yes
Generally speaking, the standard is difficult to read, focusing on how instead of what. The drafting team should strengthen the description of the outcomes, and try to reduce the reliance on the application guideline and the rationales. (One has to read the rationales before understanding the meaning of the requirements.)
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
Yes

Yes
Yes
Yes
By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an “action plan” as written in PRC-004-3. Both appear to be the same until the Rationale for R3 states “implementing an action plan of additional investigation/monitoring may determine cause and lead to the development of a CAP in accordance to Requirement R2.” Oncor recommends that additional language be added that describes the intent and difference between a CAP and an “action plan”. Oncor would also like clarification as to what authority the CEA holds in determining the effectiveness of the corrective actions detailed in the CAP and/or “action plan”.
Individual
Roger Dufresne
Hydro-Québec Procution
Yes
No
In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept(reliability of the BES) implies the analysis of all the events that occured on the BES have to be done, even if the event do not affect the reliability of the BES.
No
In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that occurred on the BES have to be done, even if the event do not affect the reliability of the BES.
No
Individual
Mauricio Guardado
Los Angeles Department of Water and Power
Yes
No
Please see answer to Question 5
No
Please see answer to Question 5
No
Please see answer to Question 5
LADWP recommends that the Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. LADWP also recommends that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.
Individual
Laurie Williams
Public Service Company of New Mexico

Yes
Yes
Yes
No
None
Individual
Bret Galbraith
Seminole Electric
The NERC STD defines a Slow Trip as a “Protection System operation that is slower than intended… .” (emphasis added). My preliminary read of this language was that if the Protection System operated slower, i.e., took even 1 cycle longer in time to operate, than how it was intended to be set, that such delay would be a Slow Trip. However, reading your responses to comments, it appears that “time” is not the measure of compliance, but in fact, the compliance metric is based on intended protective objective. By this I mean, if the overall goal of protection is met, then there is no slow trip no matter how much time has passed. To clarify even more, so as long as no additional harm has occurred during the time delay, time is not the measurement for compliance, but harm to the protected equipment is the compliance measure. With that said, can you please describe in some more detail how this compliance metric, i.e., additional harm, will be documented and audited?
1. The Proposed PRC-004-3 combines PRC-004-2a and PRC-003-1. This project is applicable to a “Distribution Provider” whereas PRC-004-2a is applicable to a “Distribution Provider that owns a transmission Protection System.” Does the STD believe that the additional caveat should be added to the Distribution Provider (DP) applicability, i.e., that the DP need to own a transmission Protection System? 2. In the “Purpose/Industry Need” section that the STD developed for this Project, the STD states that because PRC-003-1 was never approved by the Commission, “there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2… This could lead to a potential reliability gap.” (Emphasis added). This infers that there is a need for some form of standardized regional mitigation requirements. When NERC drafted PRC-003-1, NERC made RROs the applicable entity in order for each RRO to “establish, document and maintain is procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations.” (See R1. of PRC-003-1). However, in the proposed action, PRC-004-3 does not appear to require any such regional processes for misoperations mitigation. In fact, the new proposed Standard is not even applicable to RRO as the new standard does not require the RRO to perform any action. It does not appear that the new draft Standard mitigates the deficiency left by the non-approval of PRC-003-1 and so this should be addressed via the addition of some form of regional analysis requirement.
Group
Bonneville Power Administration
Jamison Dye
Yes
No
(1) The changes made to R1 are an improvement over the previous draft, but they still do not adequately clarify the responsibilities. Both the Rationale for R1 (blue box) and the Application

Guidelines indicate that the responsibility to investigate operations is placed on the owner of the interrupting device. However, BPA believes that the actual wording of R1 does not necessarily place the responsibility on the owner of the interrupting device. Instead, R1 places the responsibility on the TO, GO, or DP which has an interrupting device operation in its facility. Since it is quite common in the industry for TOs, GOs, or DPs to own interrupting devices within another entity's facility, R1 will sometimes place the responsibility on the owner of the facility where the interrupting device is located instead of on the owner of the interrupting device. In addition, the bullet points of R1 address the cases where the entity owns both the interrupting device and the protection system and where the entity owns the interrupting device but not all of the protection system, but there is no bullet point to address the case where the entity owns the protection system but not the interrupting device. It is not unusual for the owner of a facility to own a protection system but not the interrupting device that is operated by the protection system. Because it is vital that there is no ambiguity about who is responsible to initiate the investigation when an interrupting device operates, BPA recommends that the responsibility be placed on the owner of the protective relays which caused the interrupting device to operate because the owner of the protective relays will have access to the primary information that will determine how the investigation should proceed. After the owner of the protective relays makes an initial investigation, the owners of the interrupting device or the owner of other components of the protection system can be notified to investigate their part of the protection system. If the responsibility to initiate the investigation is placed on the owner of the interrupting device, that entity will have to immediately turn to the owner of the protective relays to start the investigation. (2) The use of Facility as defined by NERC in Requirement 1 does not make sense. As used in Requirement 1, Facility seems to indicate a substation or switching station, which is not in agreement with the NERC definition, which is a set of equipment that operates as a single element. BPA recommends that Facility not be used in Requirement R1 to avoid this problem.
Yes
No
R2 requires each TO, GO, or DP to develop a corrective action plan, but it does not indicate which TO, GO, or DP must do this. Is this intended to be the TO, GO, or DP that owns the interrupting device or the TO, GO, or DP that owns the protection system? BPA recommends the following wording for the beginning of R2: Each TO, GO, or DP that owns a component of a protection system identified as contributing to a misoperation, as determined per R1, shall within 60 calendar days of identifying the cause of each misoperation: (insert bullet points for R2). Similar to the comment above for R2, BPA believes that R3 does not make it clear which TO, GO, or DP the requirement applies to. BPA recommends that the entity identified by R1 as required to initiate the investigation of an interrupting device operation (BPA believes this should be the owner of the protective relays) should be the entity required to complete the actions in R3. BPA believes that similar to R2 and R3, R4 should be more specific about which TO, GO, or DP the requirement applies to. The last paragraph of the Background section states that where PRC-004-WECC-1 overlaps with this continent-wide standard, entities are expected to comply with the more stringent standard. In our comments to the previous draft, BPA suggested that the Background section simply state which of the standards takes precedence instead of leaving it to the entities to determine which standard is more stringent. The response to this comment was that entities are required to comply with both the continent-wide standard and any applicable regional standards. This response seems to contradict the Background statement. BPA requests clarification on whether entities are expected to comply with both standards or only the more stringent standard, and how an entity should determine which standard is more stringent as the standards cover very different issues. BPA believes that if an entity is expected to comply with both standards, that should be stated, or perhaps this part of the Background statement should be removed.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes

No
Austin Energy agrees with Luminant’s comment and copies it here for convenience. Requirement R1 requires all BES interrupting device operations be reviewed within 120 days. Under the Application Guidelines (Definition of a Misoperation - item 6 (page 17)), reverse power relaying used for normal unit shutdown is excluded. We recommend that this clarification be included in the Standard; either in language in the Definition of a Misoperation (items 2, 5, and 6) or in Requirement R1.
Yes
Yes
Austin Energy (AE) recommends the following changes in the Guidelines and Technical Basis section: (1) Remove the reference of reverse power relaying from item #2. This reference can be confusing because the protection scheme is used for safe shutdown of a generating unit. A substitute example would be “A failure of a “primary” loss of field relay is not a failure to trip Misoperation as long as another component of the generator’s composite Protection System opertated to shut down the generator.” (2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. AE believes this would clarify what relay systems are excluded before reading the parts of the definition and requirements. (3) The second paragraph on page 26 of the redline, which reads “With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days” is not consistent with the Standard Requirements and should be removed. The standard requires CAP development within 180 days, not CAP implementation or completion in 180 days.
(1) For events where a BES breaker operates but the Registered Entity does not own all of the Protection Systems, it is possible the other owner would not be notified until 120 days has elapsed. This is counter the the expectation of the drafting team that “it is expected that both entities will work together to investigate the cause of the operation.” Austin Energy (AE) recommends re-writing the bullets of R1 to require notification within a set number of days (AE recommends 15 calendar days) and then require the entities to work together as necessary. AE provides language revisions for consideration: R1.1. Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. --If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation. --If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, notify the other owner(s) of the Protection System component(s) within 15 calendar days. --The BES interrupting device and Protection System component owner(s) notified by the BES interrupting device owner shall work together to determine if there was a correct operation or a Misoperation of their component. (2) By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an Action Plan in the standard. They may appear to be the same. AE believes the intent of the action plan is to document an investigation plan, so recommends that additional language be added to the Rationale box for R2 that describes the intent of a CAP (as Corrective Action to avoid future recurrance) and an action plan as an investigation or other non-Corrective plan of action to investigate the cause of a misoperation or to determine if a misoperation has occured. (3) AE appreciates the efforts of the Standard Drafting Team and supports the goal of keeping the misoperation identification and correction processes as short as possible. There can be cases where extra time is necessary and the entire process may take longer than 180 days. The Standard allows for these extreme cases as written, assuming an action plan allows for the additional investigation of an operation or misoperation. For instance, if the cause of a misoperation cannot be identified, the entity may create an action plan to further research/analyze the cause (possibly the entity must ship equipment back to the OEM for cause determination). Once the cause is identified, then the Corrective Action Plan must be developed within 60 days. AE recognizes, and agrees with the Standard Drafting Team’s intent to ensure active analysis and appropriate corrective actions are adequately considered and/or implemented. Although it is likely there is sufficient time to analyze operations, identify misoperations and take corrective action for most events within the standard as written, there is a significant administrative burden involved to demonstrate action plans and/or corrective action plans are developed within the proper timelines. Therefore, although AE believes the timelines are workable as written, AE provides the following

alternative recommendation (4) Remove all of the required timelines and instead require the investigation/action plans and Corrective Action Plans only. These action plans and Corrective Action Plans contain timelines that must be followed by their very nature.
Group
Western Electricity Coordinating Council
Steve Rueckert
Sacramento Municipal Utility District
Yes
WECC believes that an Internal Controls Process with Risk Based requirements should be implemented in this standard.
Individual
E Scott Miller
MEAG
Agree
Southern Company Services - Generation

Consideration of Comments

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

The Project 2010-05.1 Drafting Team thanks all commenters who submitted comments on the proposed standard, PRC-004-3. There were 76 sets of comments, including comments from approximately 210 different people from approximately 132 companies representing all 10 of the Industry Segments as shown in the table on the following pages.

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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of Changes

The PSMSDT made substantive revisions to the previous draft 3 of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard following its previous 30-day formal comment posting of the standard and successive ballot which received 50.60% stakeholder approval. The following narrative is a summary of the substantive revisions made to the proposed draft 4 of the PRC-004-3 standard.

Definitions

Composite Protection System: The SDT is proposing a new definition to support the revisions to the definition of Misoperation.

Misoperation: The SDT made updated occurrences of "composite Protection System" with the newly proposed term of Composite Protection System. Other revisions include removing the uses of "zone," and most notably updated the category of "Slow Trip – During Fault" to address high-speed performance. The last category of "Unnecessary Trip – Other Than Fault" was modified to be clear that a Protection System operation due to on-site personnel is not a Misoperation.

Purpose

The purpose statement was reorganized to clarify that the standard applies to those Protection Systems for Bulk Electric System Elements.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Facilities

The SDT revised the Facilities section of the Applicability to remove exclusions for Special Protection Systems (SPS) and Remedial Action Schemes (RAS). As a general rule, Reliability Standards should address what is applicable, not what is excluded; therefore, SPS and RAS are not referenced in the Applicability. Exclusions concerning non-protective functions embedded within a Protection System and protective functions intended to operate as a control function (e.g., reverse power when removing a generator from service) have been moved to the main Applicability for Facilities to add clarity that these are not applicable as Protection Systems for Bulk Electric System (BES) Elements.

Effective Dates

The effective dates have not materially changed even though the language shows significant modification. This language change is being applied to Reliability Standards that are currently under development. The change is an outcome of NERC working with Canadian authorities to address their specific circumstances. Also, the Effective Date language now incorporates a provision for the Western Interconnection due to identified overlap between the Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation and the proposed continent-wide Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction. The provision is to allot time for the Western Interconnection to modify the Regional Reliability Standard.

Requirement R1

The SDT reorganized Requirement R1 to improve clarity of the required performance, allotted time periods, and a single reliability objective in a Requirement. The main part of the Requirement begins with defining what starts the review of a Misoperation, which is the operation of a BES interrupting device. In replacing the earlier Part 1.1 and its sub-bullets, the responsible entity will perform a review when the criteria (i.e., 1.1, 1.2, and 1.3) are met. The three criteria include when: the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; the BES interrupting device owner owns all or part of the Protection System component(s); and the BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. Part 1.2 is now represented in Requirement R4 to investigate the identified Misoperation to determine a cause, if not previously revealed during the initial review of a Misoperation.

There were a significant number of comments from stakeholders about the confusion between the proposed “action plan” and the “Corrective Action Plan” found in previous Requirement R3. To address these comments, the SDT created Requirement R4 to allow an entity to continue its investigation, as needed, only requiring the entity to demonstrate actions taken at least once in every two full calendar quarters toward determining the cause of an identified Misoperation.

Requirement R2

This requirement is essentially unchanged and is now represented in Requirement R5, the development of a Corrective Action Plan (CAP) to address the cause(s) of an identified Misoperation. The SDT made clarifying revisions to pinpoint the Protection System component that caused the Misoperation as being subject to the (CAP). Also, the word “first” was added before “…identifying the cause…” to improve clarity that upon identifying the “first cause” starts the 60 calendar day time period for developing the CAP. Last, the SDT added the clause “…and that no further corrective actions will be taken” to require entities to clearly state that no additional actions are planned to be taken to provide a measurable close to the performance in the declaration. Also, the phrase “would reduce BES reliability” was replaced with “would not improve BES reliability” to align with those conditions where corrective action may not be practical.

Requirement R3

This requirement was removed by the SDT in the current draft as comments revealed the use of “action plan” along with Corrective Action Plan created unnecessary confusion. The proposed Requirement R4 fills this performance by requiring entities to continue its investigative actions in determining a cause of an identified Misoperation.

Requirement R4

This requirement is now Requirement R6 and is essentially the same as the previous Requirement R4, except that “action plan” was removed. Implementation is further clarified that the CAP must be updated when actions or timetables change through completion of the CAP.”

Compliance

The SDT corrected this section to comport with the standard language NERC uses in Reliability Standards. Also, the Evidence Retention section was changed to reduce the minimum time periods that were previously proposed at six years (i.e., the last audit) for all Requirements to 12 calendar months for all Requirements according to the Standard Drafting Guidelines for evidence retention.

VRFs and VSLs

After further review, the SDT lowered the earlier Requirement R4 (implement the CAP) Violation Risk Level (VRF) from High to Medium. This comports with the VRF found in PRC-016-0.1 – Special Protection System Misoperation, Requirement R2 and PRC-022-1 - Under-Voltage Load Shedding Program Performance, Requirement R1.2. See the VRF and VSL Justifications document for additional information.

The Violation Severity Levels were completely rewritten due to the substantive changes made in restructuring the Requirements to meet a single reliability objective in a requirement. The SDT notes that it applied the VSL Guidelines in establishing the VSLs including the incremental differences between each level.

Application Guidelines

The SDT substantially reorganized the Guidelines and Technical Basis section of the Application Guidelines for organization and flow. Section headers were added and reordered as well as creating additional examples for guidance. For instance, the examples for Requirement R5 and R6 mirror one another to demonstrate an example of Corrective Action Plan (CAP) development (R5) and its implementation (R6).

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Russel Mountjoy	Midwest Reliability Organization NERC Standards Review Forum (NSRF)	X	X	X	X	X	X		X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joeseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
2.	Kenneth Goldsmith	Alliant Energy	MRO	4, 8
3.	Jodi Jensen	Western Area Power Administration	MRO	1, 6
4.	Terry Harbor	MidAmerican Energy Company	MRO	1, 3, 5, 6
5.	Mike Brytowski	Great River Energy	MRO	
6.	Scott Nickels	Rochester Public Utilities	MRO	4, 5
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5
8.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6

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

10.	Dan Inman	Minnkota Power Cooperative	MRO	1
11.	Marie Knox	Midwest ISO, Inc	MRO	2
12.	Lee Kittleson	Otter Tail Power Cooperative	MRO	1, 5
13.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Charles Morgan	Colorado Springs Utilities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Morland	Colorado Spring Utilities	WECC	1
2.	Warren Rust	Colorado Spring Utilities	WECC	1
3.	Donald Loftis	Colorado Spring Utilities	WECC	1
4.	Travis Dorr	Colorado Spring Utilities	WECC	5
5.	Shannon Fair	Colorado Spring Utilities	WECC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1

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

18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Brian Robinson	Utility Services	NPCC	8
20. Brian Shanahan	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Mary Jo Cooper	Mary Jo Cooper	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Ken Dize	Salmon River Electric Coop	WECC	1, 2
2. Elizabeth Kirkley	City of Lodi	WECC	2
3. Angela Kimmey	City of Pasadena	WECC	1, 2
4. Sam Rohn	California Pacific Electric Company	WECC	2
5. Colin Murphey	City of Ukiah	WECC	2
6. Douglas Draeger	Alameda Municipal Power	WECC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Charles Yeung	ISO RTO Council Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Greg Campoli	NYISO	NPCC	2
2. Bill Phillips	MISO	RFC	2
3. Steve Myers	ERCOT	ERCOT	2
4. Ben Li	IESO	NPCC	2
5. Matt Goldberg	ISONE	NPCC	2
6. Tom Bowe	PJM	RFC	2
7. Ali Miremadi	CAISO	WECC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	paul haase	seattle city light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. pawel krupa	seattle city light	WECC	1
2. dana wheelock	seattle city light	WECC	3
3. hao li	seattle city light	WECC	4
4. mike haynes	seattle city light	WECC	5

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

5.	dennis sismaet	seattle city light	WECC	6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Poo	SPP	NA
3.	James Nail	City Of independence, Missouri	SPP	3
4.	Ken Zellefrow	City Utilities	SPP	1, 4
5.	David Oswald	Empire District Electric Company	SPP	1
6.	Cole Brodine	Nebraska Public Power District	MRO	1, 3, 5
7.	Gordon Heins	Nebraska Public Power District	MRO	1, 3, 5
8.	Greg Hill	Nebraska Public Power District	MRO	1, 3, 5
9.	Stephen Wadas	Nebraska Public Power District	MRO	1, 3, 5
10.	Shawn Jacobs	Oklahoma Gas and Electric Company	SPP	1, 3, 5
11.	John Hare	Oklahoma Gas and Electric Company	SPP	1, 3, 5
12.	Mike Sheriff	Oklahoma Gas and Electric Company	SPP	1, 3, 5
13.	Jamie Strickland	Oklahoma Gas and Electric Company	SPP	1, 3, 5
14.	Tiffany Lake	Westar Energy, Inc	SPP	1, 3, 5, 6
15.	Bo Jones	Westar Energy, Kansas Gas and Electric	SPP	1, 3, 5, 6
16.	Tim Bobb	Westar Energy, Inc	SPP	1, 3, 5, 6
17.	Lynn Schroeder	Westar Energy, Inc	SPP	1, 3, 5, 6
18.	Paul Von Hertsenberg	Westar Energy, Inc	SPP	1, 3, 5, 6
19.	Mahmood Safi	OPPD	MRO	1, 3, 5

				1	2	3	4	5	6	7	8	9	10
8.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Co	RFC	3
2.	Alvin Deperw	Pepco Holdings Inc	RFC	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Chang Choi	City of Tacoma, Tacoma Public Utilities	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4

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

3.	Chris Mattson	Tacoma Power	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

				1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc	RFC	5, 6
2.	Connie Lowe	Dominion Resources Services, Inc.	SERC	1, 3, 5, 6
3.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
11.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

.

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	DeWayne Scott		SERC	1
5.	Thomas Vandervort		SERC	5
6.	M Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Jeff Galyon		SERC	5
9.	M Lee Thomas		SERC	5
10.	Henry (Pat) Caldwell		SERC	1

				1	2	3	4	5	6	7	8	9	10
12.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

				1	2	3	4	5	6	7	8	9	10
13.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		

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

2. Phil Winston	Southern Company		
3. John Miller	Georgia Transmission Co.		
4. Jay Farrington	PowerSouth		
5. Charles Fink	Entergy		
6. Steve Edwards	Dominion		
7. George Pitts	TVA		
8. Bridget Coffman	Santee cooper		
9. Russ Evans	Scana		
10. David Greene	SERC		

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

Additional Member	Additional Organization	Region	Segment Selection
1. Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6. Randy Hahn	Ocala Utility Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
15.	Group	Ben Engelby	ACES Standard Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
2. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
3. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
4. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
5. Susan Sosbe	Wabash Valley Power Association	RFC	3
6. Tom Alban	Buckeye Power, Inc.	RFC	3, 4

				1	2	3	4	5	6	7	8	9	10
16.	Group	Tom McElhinney	JEA	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ted Hobson		FRCC	1
2. Garry Baker		FRCC	3
3. John Babik		FRCC	5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Group	Brent Ingebrigtson	PPL NERC Registered Entities	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Entities	RFC	5
3.	Annette Bannon	PPL Generation, LLC on behalf of Supply NERC Registered Entities	WECC	5
4.	Elizabeth Davis	PPL Energy Plus, LLC	MRO	6
5.	Elizabeth Davis	PPL Energy Plus, LLC	NPCC	6
6.	Elizabeth Davis	PPL Energy Plus, LLC	SERC	6
7.	Elizabeth Davis	PPL Energy Plus, LLC	SPP	6
8.	Elizabeth Davis	PPL Energy Plus, LLC	RFC	6
9.	Elizabeth Davis	PPL Energy Plus, LLC	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	Technical Svcs	WECC	1
2.	Dan Goodrich	Technical Operations	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Ed Croft	Operational Compliance	X		X		X					
22.	Individual	Pamela R. Hunter	Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
23.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
24.	Individual	Greg Froehling	Rayburn Country Electric Cooperative			X							
25.	Individual	John Miller	Georgia Transmission Corp	X									
26.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
27.	Individual	Michael Moltane	ITC Holdings	X									

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
29.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
30.	Individual	Patrick Brown	Essential Power, LLC					X					
31.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
32.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
33.	Individual	Jack Stamper	Clark Public Utilities	X									
34.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
35.	Individual	Bill Middaugh	Tri-State G&T	X									
36.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
37.	Individual	Joseph DePoorter	Madison Gas and Electric Company			X	X	X	X				
38.	Individual	John Bee	Exelon Corporation and it's affiliates	X		X		X					
39.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
40.	Individual	NICOLE BUCKMAN	Atlantic City Electric Company			X							
41.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
42.	Individual	Jim Cyrulewski	JDRJC Associates LLC								X		
43.	Individual	Thad Ness	American Electric Power	X		X		X	X				
44.	Individual	Anthony Jablonski	ReliabilityFirst										X
45.	Individual	Mary Downey	City of Redding			X	X	X	X				
46.	Individual	Jonathan Meyer	Idaho Power Company	X									
47.	Individual	Bill Fowler	City of Tallahassee			X							
48.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
49.	Individual	Don Jones	Texas Reliability Entity										X
50.	Individual	Wryan Feil	Northeast Utilities	X									
51.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
52.	Individual	Mark Yerger	Pepco Holdings, Inc Segment 1			X							
53.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
54.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
55.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
56.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
57.	Individual	Joylyn Faust	Consumers Energy			X	X	X					
58.	Individual	Daniela Hammons	CenterPoint Energy	X									
59.	Individual	Kenn Backholm	Public Utility District No. 1 of Snohomish County	X		X	X	X	X				
60.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
61.	Individual	David Jendras	Ameren	X		X		X	X				
62.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X		X			
63.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
64.	Individual	Cole Brodine	Nebraska Public Power District	X		X		X					
65.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
66.	Individual	Scott Langston	City of Tallahassee	X									
67.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
68.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
69.	Individual	Michael Falvo	Independent Electricity System Operator		X								
70.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
71.	Individual	Roger Dufresne	Hydro-Québec Procution					X					
72.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
73.	Individual	Laurie Williams	Public Service Company of New Mexico	X		X							
74.	Individual	Bret Galbraith	Seminole Electric			X	X	X	X				
75.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
76.	Individual	E Scott Miller	MEAG	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

The drafting team thanks you for your comments and for simplifying the effort in responding to comments by supporting other entities comments and avoiding unnecessary duplication. Please see the commenting entity's comments for the drafting team's responses.

Organization	Supporting Comments of "Entity Name"
City of Redding	BANC/SMUD
Illinois Municipal Electric Agency	Florida Municipal Power Agency
Indiana Municipal Power Agency	Florida Municipal Power Agency
JDRJC Associates LLC	Midwest ISO
Lincoln Electric System	MRO NSRF
US Army Corps of Engineers	MRO NSRF
Alliant Energy	MRO NSRF
The United Illuminating Company	Northeast Power Coordinating Council (NPCC)
Atlantic City Electric Company	Pepco Holdings Inc and Affiliates
Delmarva Power & Light Company	Pepco Holdings Inc and Affiliates

Organization	Supporting Comments of “Entity Name”
Pepco Holdings, Inc Segment 1	Pepco Holdings Inc and Affiliates, Segment 1
Western Electricity Coordinating Council	Sacramento Municipal Utility District
Clark Public Utilities	Sacremento Municipal Utility District
MEAG	Southern Company Services - Generation

1. **Based on stakeholder input, the drafting team revised the definition of a Misoperation. The categories as well as the introductory sentence of the definition were modified for clarity. The introductory sentence indicates that a Misoperation pertains to 'the failure of an Element's composite Protection System to operate as intended.' Do you agree with the revised definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The following resulted in a revision to the proposed standard. There were approximately 15 comments supported by 44 individuals concerns expressing concern about the "Slow Trip – During Fault" category of the proposed Misoperation definition. Concerns varied and included; a reference to the NERC Transmission Planning (TPL) Reliability Standards which was removed; the need for precise operating times which were clarified in the Application Guidelines; compliance concerns questioning how entities will be measured in this category; and last, what if adequate data was not available to make a determination.

Concerning the use of the phrase "composite Protection System," there were about four comments representing about 24 individuals requesting clarification which also resulted in a modification to the proposed standard. The drafting team is proposing the new term "Composite Protection System" for inclusion in the *Glossary of Terms used in NERC Reliability Standards*.

The last item that resulted in a change to the proposed standard concerned on-site activities pertaining to the Misoperation definition category, "Unnecessary Trip – Other Than Fault." This was supported by two minority comments and individuals requesting clarity that an operation due to on-site or activity activities that result in a Protection System operation would not be a Misoperation. The drafting team concurred and made clarifications to this last category.

The following did not result in a change to the proposed standard. Approximately eight comments supported by about 17 individuals were concerned that the proposed definition of Misoperation (or standard) was inferring that entities will be required to install Disturbance Monitoring Equipment (DME). Although useful in determinations (i.e., slow trips), the standard nor definition require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018).

One comment supported by about 17 individuals requested that a Reliability Standard Audit Worksheet (RSAW) be posted contemporaneously with the proposed standard and definition of Misoperation. The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3.

Last, a minority set of comments from approximately ten individuals concerning the "Slow Trip – During Fault" offered suggestions that were not implemented – in the judgment of the drafting team, these suggestions did not provide improve clarity.

Organization	Yes or No	Question 1 Comment
ACES Standard Collaborators	No	(1) The term “composite” Protection System is unclear, used inconsistently and should be defined. Based on the first sentence on Page 14 of the Guidelines and Technical Basis section, it appears that all Protection Systems protecting an Element are intended to be included in composite Protection System. That is any primary, secondary, backup, pilot and non-pilot relay schemes for a given Element would be included in its composite Protection System. If this is the case, we suggest just writing a definition so it will be clear where the term comes from and what the meaning is. However, it is not clear that the term is even needed since the definition of Protection System would already include all of these Protection Systems. The definition includes “Protective relays which respond to electrical quantities.” The inconsistent use of “composite” in the standard documents only creates more questions for the need of the definition. For example, on page 14 of Guidelines and Technical Basis section under the section (1) title, the “overall performance of the Protection System for the Element it is designed to protect” is used. This is understood to be all “protective relays” including secondary, backup, pilot and non-pilot relay schemes. As defined, Protection System includes the plural use of protective relays so all could be included. **Response:** The use of the term “composite” Protection System is intended to address the fact that the term Protection System by itself does not indicate that it is the complete set of protective relaying for an Element such as any primary, secondary, local backup, and communication-assisted relay systems. The word “composite” used as a modifier to Protection System was developed by the NERC SPCS to indicate the total complement of protection for a system Element (line, bus, transformer, generator, etc). To clarify the usage of the terminology, the drafting team is proposing a definition for “Composite Protection System” and has made corresponding changes where “composite Protection System” occurs in the body of the project documents. Change made. (2) Why does the definition need an introductory sentence? The clarifying statement “any of the following is considered a Misoperation” provides the same outcome. Also, several of the sub-parts of the definition discuss the “overall performance of the

Organization	Yes or No	Question 1 Comment
		Protection System," so this introductory sentence seems redundant. Instead of adding confusion, we recommend that the drafting team strike the entire introduction sentence of the definition. **Response:** The introductory sentence provides the essential introduction to the numbered parts. The six categories provide the different categories of a Misoperation which classify a Misoperation in terms of Fault or non-Fault conditions, and security or dependability. No change made. (3) For sub-part "3. Slow Trip - During Fault" of the definition, we recommend revising the second sentence. It is a run-on sentence, uses incorrect grammar, contains a triple negative statement, and is confusing. We recommend revising the sentence to clearly state when delayed fault clearing should be excluded and what conditions must be met before the operation is not to be considered a Misoperation. **Response:** The drafting team agrees and is proposing a revision of "Slow Trip - During Fault" to address this comment and others. Change made. (4) For sub-part "5. Unnecessary Trip - During Fault" of the definition, we believe that the revised sentence now overlaps other sub-parts of the definition. "A Protection System operation for a Fault for which the Protection System is not intended to operate" is almost the exact definition of Misoperation in the introductory sentence. Nothing in this sub-part discusses an unnecessary trip. The phrase "not intended to operate" could apply to all of the other sub-parts because a failure to trip, slow trip, or unnecessary to trip would be the result of a Protection System not operating the way it was intended. More detail is needed for this sub-part. **Response:** The drafting team agrees and is proposing a revision of "Unnecessary Trip – During Fault" to make clear that this part is for an unnecessary operation for a Fault on another Element. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 1 Comment
Xcel Energy	No	a. (This is the single issue causing us to vote negative.) Many generating units with legacy electromechanical protective relay based protection systems do not have DME for high-speed recording of relay-operation events. Although the generating circuit breakers may be on the HV side of GSU transformers and may be monitored via the associated substation DME, the initiating signals from protective relays on the generator side of the GSU may not provide an input or trigger signal to the substation DME. As such, there is little or no value in requiring Generator Owners to try to identify and analyze slow trip events when such data to perform the analysis is not required to be available. In particular, we are concerned that examples provided in the Slow to Trip - Other than Fault bullet of the Misoperation definition (undervoltage, over excitation and loss of excitation) point explicitly toward application of this portion of the definition towards Generator Owners. We are concerned how various auditors may judge entirely qualitative evaluations of the adequacy of GO Protection System performance for Slow to Trip - Other than Fault events when DME is not available, nor required, to quantify performance. **Response:** The definition and standard do not require the installation of Disturbance Monitoring Equipment (DME); however, the entity must use its available information to determine whether there was a Misoperation. The standard requires all applicable entities to review Protection System operations for Misoperation. Other changes were made to category “4. Slow to Trip - Other than Fault” to identify other conditions for these types of Misoperations and to incorporate the proposed term “Composite Protection System.” Change made. b. Under "Slow Trip - During Fault", is the phrase “Delayed Fault clearing" intended to be the same as the Glossary term “Delayed Fault Clearing”? If not, the similarity of the existing usage with the defined term introduces ambiguity and confusion about intent. Suggest rewording the second sentence under "Slow Trip - During Fault" to eliminate this potential confusion. Note that similar confusion between the term “Delayed Clearing” used in TPL Standards and the Glossary term “Delayed Fault Clearing” resulted in the NERC Interpretation Request 2012-INT-02.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team did not intend "Delayed Fault clearing" to be associated with the NERC glossary definition. The NERC glossary term, "Fault," was moved to improve the clarity for "Slow Trip – During Fault." Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Electric Power	No	AEP recommends removing the reference to "TPL standards" from the "Slow Trip - During Fault" category of the definition. AEP believes the intent of the "TPL standards" reference can be maintained by capturing all slow trip events that result in clearing more Elements than necessary. **Response:** The drafting team agrees and has removed the TPL standards reference from "Slow Trip – During Fault." Change made. AEP's first preference is to reword the category as follows "Slow Trip - During Fault - An Element's composite Protection System operation that, due to the duration of the composite Protection System's operating time, resulted in the clearing of other Elements in addition to the Faulted Element.". AEP's second preference is "Slow Trip - During Fault - A composite Protection System operation for the Faulted Element it was designed to protect which was slower than intended. Delayed Fault Clearing due to the non-operation of an installed high-speed protection scheme is not a Misoperation provided the duration of the composite Protection System's operating time did not result in instability or cascading, and did not result in miscoordination with any other composite Protection Systems." **Response:** The drafting team disagrees with the first suggestion. Remote backup Protection System operation before the Fault is cleared is one indicator of a slow trip. A Composite Protection System that operates slower than required for a Fault on an Element is a Misoperation regardless of whether other Elements operated or not. The drafting team disagrees with the second suggestion because the Composite Protection System must operate as intended (e.g., meet the intended high-speed operation) regardless of whether something bad happened or not. The drafting team

Organization	Yes or No	Question 1 Comment
		made other clarifying changes to the definition of Misoperation. Change made. AEP recommends adding to both “Failure to Trip - During Fault” and “Failure to Trip - other than Fault” - “Please see Category 3(4) to determine if the “slow trip” classification applies to the operation.” **Response:** The drafting team does not agree that adding references to category 3 (or 4) at the end of category 1 (or 2) is needed. These same types of references could apply elsewhere in the definition and only complicate the definition. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Lincoln Electric System	No	Although supportive of the proposed revisions to the definition of Misoperation, LES is concerned that the phrase “slower than intended” within the definition of a “Slow Trip - During Fault” may lead to unnecessary administrative work in an effort to prove what is considered an acceptable operation time for each Protection System. To avoid requiring entities to develop documentation stating “how fast is fast enough”, recommend modifying the Application Guidelines as follows: (3) ...The phrase “slower than intended” means the Protection System operated slower than the objective of the owner(s). It would be impossible to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System operation was adequate. [The intent is not to require documentation of adequate Protection System operation times, but to assure consideration by the owner(s) reviewing each Protection System operation.]
Response: The drafting team thanks you for your comments and agrees with your sentiment and will add an extra sentence in the paragraph noted in the Application Guidelines regarding the intent. Also, the part of the definition “Slow Trip – During Fault” has		

Organization	Yes or No	Question 1 Comment
been revised to improve clarity. Change made.		
Florida Municipal Power Agency	No	FMPA appreciates the response to our comments, but, we do not believe our issues have been resolved. First, on “Slow Trip”; however, we disagree with your perspective. The SDT is taking a relativistic approach to time, e.g., interpreting the words it drafted “slower than intended” as relating to whether the Protection System operated “fast enough to prevent additional harm” and not a more common interpretation of it operated slower than it was designed to operate. FMPA believes that an auditor would interpret this using the latter interpretation and instead ask for the design clearing time of the protection system as a comparison of whether actual operation was “slow”, e.g., if the system is designed to operate in 5 or 6 cycles and instead it operates in 7 or 8 cycles, fast enough to prevent backup protection from operating, but slower than designed, is that slow? If the SDT intends “slower than intended” to mean that it operates “fast enough to prevent any additional harm”, e.g., the clearing time of the back-up protection, then state that in the definition. The response to our comment (and the Application Guidelines) focuses on the owner of the Protection System “should have an understanding of the objectives of its Protection Systems”; that is not FMPA’s concern. FMPA’s concern is how an auditor will audit R1 and verify that the entity identified all misoperations, and how an auditor will interpret “slower than intended”. **Response:** The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines.

Organization	Yes or No	Question 1 Comment
		Change made. Second, FMPA commented last time (commenting on R1) on the difficulty of measuring whether a fault actually occurred and where the fault in regards to the definitions of “Failure to Trip” and “Unnecesary Trip”. For both, an auditable investigation would need to determine if: 1) a fault actually existed, which can be quite difficult to verify for something like a lighnting strike with automatic reclosing; and 2) where the fault was; so that it can be determined whether or not the fault was “within the zone it was designed to protect”. In investigating tripping of BES Elements, a large number of those events are indeterminent, meaning that physical evidence could not be found. With microprocessor based protection systems, if may be possible to set up a sort of event recording function that may be able to provide evidence of fault condition and roughly where a fault was; however, with electromechanical relays, that is not possible without installing additional equipment. Is the SDT intending to require a form of event recording at each substation so that the existence and location of a fault can be determined for every protection system trip? If no evidence of a fault exists, would the default assumption be that everything operated as intended unless the evidence of protection system operation indicated otherwise (e.g., both primary and backup systems operated)? If that is the intent, then that intent should be stated within the requirements. **Response:** Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could

Organization	Yes or No	Question 1 Comment
		document the operation was correct. No change made. Third, how would a high impedance fault be treated? Such a fault could occur within the relay reach, but, the impedance of the fault could in essence cause the fault to appear further away than it actually is. For instance, assume a line is protected by an instantaneous ground overcurrent relay protecting about 70% of the line and by an inverse time ground overcurrent relay as local backup. And let's say a high impedance fault occurs 50% of the length of the line, but the impedance of the fault reduced the fault current to below the instantaneous relay setting such that the inverse time ground overcurrent relay operates instead. Is that a misoperation because the instantaneous ground overcurrent relay failed to operate for a "Fault within the zone it was designed to protect"? Which leads to the ambiguity of the phrase "within the zone it was designed to protect". Does zone mean a distance as derived from the relay settings, or is it the relay settings themselves? If it is the relay settings themselves, then FMPA suggests changing the phrase to eliminate "zone" and instead refer to the actual protection system settings. **Response:** The example provided would not be a Misoperation simply because the instantaneous element in the relay did not operate. The drafting team has removed the reference(s) to "zone" in the proposed definition of Misoperation. Change made. Fourth, FMPA is also concerned about how "composite Protection Systems" works, especially with the combination of "within the zone it was designed to protect". For instance, let's assume Line 1 has typical stepped disctance scheme of zones, 1 through 3, and let's assume the adjacent Line 2 has a fault and there is a failed breaker at the intermediate substation. The breaker is not part of any protection system, but, the zone 3 remote backup relay of Line 1 operates to help clear the fault on Line 2, which is a correct operation. So, is Line 1's zone 3 relay part of Line 1's composite Protection System, and if so, then there is not a single "zone" for composite Protection Systems, which again adds to the ambiguity of the phrase "within the zone it is designed to protect".

Organization	Yes or No	Question 1 Comment
		Response: Line 1's zone 3 is a backup relay element that covers Line 1's primary zone of protection and provides remote protection for other zones. In the example cited, the zone 3 operation is not a Misoperation because it provided proper backup for Line 2 and its zone of protection extends into Line 2. The prior use of the phrase "composite Protection System" was intended to indicate that the collective operations of the entire Protection Systems for an Element that determines whether a Misoperation occurred. To clarify the usage of the phrase, the drafting team is proposing a definition for "Composite Protection System." Change made. Fifth, some misoperations are due to mistakes made by protection engineers, e.g., mistakes in establishing relay settings; so does: "within the zone it was designed to protect" the actual design of the protection engineer, e.g., the mistaken relay setting, or what the design should have been? If the latter, how will the 'what the design should have been' be determined? If the SDT has not already done so, FMPA recommends involving NERC and RE enforcement staff to discuss how R1 would be audited in combination with these definitions. **Response:** "Within the zone it was designed to protect" referred to the intended design. The entity must determine and know the intended zone of protection. The drafting team has removed the reference(s) to "zone" in the proposed definition of Misoperation. An incorrect design is a valid cause of a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Liberty Electric Power LLC	No	I agree with the position of the Standards Development Team of the North American Generator Forum, which states: The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may

Organization	Yes or No	Question 1 Comment
		therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. The standard does, however, require entities to determine if Protection System operations were correct or were Misoperations. Misoperations should be investigated and the causes of those Misoperations should be corrected. To consider if a slow trip Misoperation occurred, the entity must determine if the Protection System operation resulted (due to the operating time) in either the operation of other Elements, instability, or slower than required for a Fault condition for which it was designed. The categories of the definition that are associated with slow trips have been modified to help identify the conditions for these types of Misoperations. No change made.		
Rayburn Country Electric Cooperative	No	I suggest using the word “entire” versus “composite” for clarity sake. composite (adj) Merriam Webste of or relating to a very large family entire (adj) Merriam Webster having no element or part left out ELEMENT NERC Glossary Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be

Organization	Yes or No	Question 1 Comment
		comprised of one or more components.
Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term "Composite Protection System." Change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration believes that the latest version of the definition correctly captures the intent that the action of the composite Protection System is the gating factor in the determination of a Misoperation. The aggregate action of the primary, secondary, and pilot systems should form the basis of the expected performance, not each individual group of components. However, we still believe that the project team's intent to allow Protection System owners some flexibility to determine when a "slow trip" occurs is not captured. We fully agree with your statement in the last Consideration of Comments that it is up to the owners to have "an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent any additional harm, and ultimately be able to decide whether the speed or outcome of its Protection System was adequate." However, unless the language is captured in the standard or the definition, CEAs may choose a different basis. In the extreme, they may determine that any delay outside the settings or manufacturer's specifications to be a Misoperation - even if reliability is not threatened or monitoring equipment cannot resolve down to that level of granularity.
Response: The drafting team thanks you for your comments and cannot speak to the approach that might be used by the Compliance Enforcement Authority (CEA). Based on the Requirements and definition of Misoperation, an entity must identify any Misoperation according to the information available at the time. The drafting team is proposing a definition for "Composite Protection System." The categories of the definition that are associated with slow trips have been revised to identify the other conditions for these types of Misoperations. No change made.		
Independent Electricity System Operator	No	NPCC uses different terms, such as failure to operate (not operating when required) vs misoperation (operating when not required). We think that the definition here has the intention of defining more generally an "incorrect operation", and perhaps the

Organization	Yes or No	Question 1 Comment
		"incorrect operation" should be used for both different terms.
Response: The drafting team thanks you for your comments. The defined term “Misoperation” in the *Glossary of Terms used in NERC Reliability Standards* covers Protection System security and dependability failures. The proposed Misoperation definition revision is intended to provide additional clarity. No change made.		
PacifiCorp	No	PacifiCorp believes that the definition used for a Slow Trip During Fault misoperation on Page 4 should be amended to provide more clarity. The current definition reads as follows: ”Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.” PacifiCorp suggests changing “identified to meet” to “identified as necessary to meet.”
Response: The drafting team thanks you for your comments and has revised the “Slow Trip - During Fault” category of the proposed Misoperation definition to incorporate this suggestion. Change made.		
City of Tallahassee	No	Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. **Response:** If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made. Also, it can be difficult at times to determine if a fault actually occurred within a relay’s

Organization	Yes or No	Question 1 Comment
		zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault. **Response:** Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Tallahassee	No	Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. **Response:** If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made. Also, it can be difficult at times to determine if a fault actually occurred within a relay’s zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault. **Response:** Although it is true that it may be difficult to precisely locate a Fault, it is

Organization	Yes or No	Question 1 Comment
		incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Tallahassee - Electric Utility	No	Some of the scenerios for possible mis-operations are too vague. For example what constitutes a slow trip and what would constitute how a protection system is designed? If a protection scheme is designed to trip in 2-3 cycles and it trips in 5-6 cycles yet still protects the equipment, an auditor could see that as a mis-operation however it still would protect the equipment as it was designed. **Response:** If the Protection System operates slower than required on the Element(s) it is designed to protect or the Protection System operates slower than what was previously identified as being necessary to prevent voltage or dynamic instability, then it is a “Slow Trip” Misoperation. Your example would not be a Misoperation unless it resulted in an over-trip or instability. No change made. Also, it can be difficult at times to determine if a fault actually occurred within a relay’s zone of reach. If a bolt of lightning causes a fault on a line unless there is physical damage there can be little visual indication of a fault. It can be difficult to confirm if a mis-operation occurred if you can not first confirm what caused the fault. **Response:** Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. An entity should review the evidence it can obtain for

Organization	Yes or No	Question 1 Comment
		an event, and if there is no evidence of a Misoperation, then the entity could document the operation was correct. No change made. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Entergy Services, Inc. (Transmission)	No	Suggest Misoperation definition #6 be revised from “unrelated to on-site maintenance....” to “unrelated to maintenance....” to clearly allow as an exclusion, a Protection System maintenance or commissioning activity which results in an inadvertent remote end station trip. For example, a direct transfer trip scheme.
Response: The drafting team thanks you for your comments. It is important to emphasize that the maintenance exclusion is for active maintenance. A remote-end trip is included in the existing exclusion if it resulted from “on-site” activities at a different location. The Application Guidelines have also been enhanced with an example (6d) related to this topic. Change made.		
Dominion	No	The addition of the word “composite” adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made.		
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	No	The NSRF would like to see a RSAW for this particular standard to better understand what level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. For instance if you didn’t have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips.
Response: The drafting team thanks you for your comments. The drafting team anticipates posting a draft PRC-004-3 RSAW so that		

Organization	Yes or No	Question 1 Comment
entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.		
Tennessee Valley Authority	No	The proposed Misoperation definition is based on the "Protection System" definition defined in the NERC Glossary of Terms (GoT). However, the NERC GoT does not provide the elements that are considered "Protective System" elements. The actual descriptions of the "Protection System" elements are found in PRC-005-2, 4.2 Faciliities. Recommend this PRC-004-3 revision include a new GoT definition of "Protective System Element" based on PRC-005-2, 4.2, Facilities, or a revision to the NERC GoT to include an abbreviated summary of the PRC-005, 4.2, Facilities in the "Protection System" definition; or include an abbreviated summary of the PRC-005-2, 4.2 Facilities into the PRC-004-3 definition of "Misoperations;" or revise both the NER GoT definition of "Protection System", and PRC-004-3 definition of "Misoperation" to reference PRC-005, 4.2, Facilities, as the elements that are "Protection System elements."
Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made.		
Duke Energy	No	The revised definition still contains the incorrect reference to TPL standards in "Slow Trip - During Fault". The TPL standards Category A, B and C do not require Planning to identify every place where high speed protection is required for dynamic stability. If a Category B issue is identified, high speed protection is installed and it is no longer on the Category B list. If a Category C issue is identified, a redundant relay scheme is installed and it is no longer a Category C issue. Therefore, the list of places where "high-speed performance has been identified to meet the dynamic stability performance requirements of the TPL standards" is just a list of where the appropriate corrective action has not yet been implemented and could, in theory, be empty.

Organization	Yes or No	Question 1 Comment
		“Slow Trip - During Fault” should be revised as follows: “A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified as needed by the Planning Authority or the Transmission Operator, or if it is not required to ensure coordination with other Protection Systems.”
Response: The drafting team thanks you for your comments. The reference to the TPL standards in both the Misoperation definition and body of the standard has been removed. Change made.		
ReliabilityFirst	No	The revision to part three of the definition that converted the original parenthetical example into an exclusion by stating it inversely creates a potential loophole. The revised wording would consider correct the slow operation of a Protection System that caused avoidable equipment damage (due to the delayed fault clearing) as long as it did not cause a dynamic stability or coordination issue. The Protection System also needs to coordinate with the damage curves of the equipment within its zone. As the exclusionary sentence stands, it actually uses double negatives. It would be better to restate the sentence positively. A suggested improvement would to replace the second sentence in part three of the definition with the following: Delayed Fault clearing associated with an installed high-speed protection scheme is an example of a Misoperation if high-speed performance is required to meet the dynamic stability performance of the TPL standards or is required to ensure coordination with other Protection Systems.
Response: The drafting team thanks you for your comments and has modified the “Slow Trip - During Fault” category of the Misoperation definition. Change made.		
Texas Reliability Entity	No	The SDT may want to consider adding loadability as an example under “Failure to Trip - Other Than Fault” and under “Unnecessary Trip - Other Than Fault”. **Response:** It would be incorrect to add loadability as an example under “Failure to Trip

Organization	Yes or No	Question 1 Comment
		– Other than Fault" as normally there would not be a need to trip under load. There are no inclusion examples under "Unnecessary Trip - Other Than Fault" as this category could include a broad range of conditions including normal conditions. The examples in this category are exclusionary and loadability is not a case that should be excluded. No Change made. The existing definition of the 'Slow Trip-During Fault' needs to include that the delayed fault clearing associated with the installed high-speed performance of the protection system is not required to meet the voltage ride-through capabilities of the generators. Generators should not be tripping off line due to suppressed voltage in the system stemming from the delayed fault clearing. This could create steady state voltage issues. Suggested language: "Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems ***or result in loss of generation due to delayed fault clearing time***." Also, the definition of "Slow Trip - During Fault" refers to stability performance requirements of the TPL Standards, however, the TPL Standards do not cover delayed three-phase fault clearing studies. Delayed three-phase fault clearing can create undesired system conditions. **Response:** The suggested condition, loss of generation due to delayed fault clearing time, is a specific class of coordination issues which are included in the "Slow Trip - During Fault" part of the Misoperation definition. "Slow Trip - During Fault" has been revised and the reference to the TPL standards has been removed. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 1 Comment
Cogentrix Energy Power Management, LLC	No	The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: - The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. - Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. - The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). - Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.

Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences.

The standard does, however, require entities to determine if Protection System operations were correct or were Misoperations. Misoperations should be investigated and the causes of those Misoperations should be corrected. To consider if a slow trip Misoperation occurred, the entity must determine if the Protection System operation resulted (due to the operating time) in either the operation of other Elements or instability, or slower than required for a Fault condition for which it was designed. The categories of the definition that are associated with slow trips have been modified to help identify the conditions for these types of Misoperations. No change made.

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Entities	No	The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: o The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. o Where DME is present it is generally installed on the HV side of a unit, and may therefore not yield any useful information for problems occurring at the generator or other low-side components. o The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). o Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.		
Essential Power, LLC	No	The topic of slow trips should be removed from PRC-004-3 and the proposed re-definition of a Misoperation, for the following reasons: -The standard incorrectly assumes that every NERC-registered generation unit is required to have DME for high-speed recording of relay-operation events. -Where DME is present it is generally installed on the HV side of a unit, and may

Organization	Yes or No	Question 1 Comment
		therefore not yield any useful information for problems occurring at the generator or other low-side components. -The standard incorrectly assumes that all GOs have, or should have, design-level relay personnel, ref. the Application Guidelines statements regarding being able to decide whether the speed of the Protection System was adequate (pp. 15 and 16). -Independent GOs in particular have finite resources, and mandating an unreasonable focus on Protection System event record-keeping and analysis will leave other operation and maintenance tasks that much less well covered, resulting in a negative impact on reliability.
Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	1) Please revise the Slow Trip - During Fault second sentence for clarity. We suggest: “Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation unless the high-speed performance has either been identified to meet the dynamic stability performance requirements of the TPL standards, or is required to ensure coordination with other Protection Systems.” **Response:** The “Slow Trip - During Fault” category of the definition has been revised for clarity. Change made. 2) We suggest clarifying Definition (6) by replacing "is unrelated to on-site" with "the

Organization	Yes or No	Question 1 Comment
		Protection System that operated is not directly associated with" as shown below to be consistent with page 17, and to exclude transfer trip testing: Unnecessary Trip - Other Than Fault - A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and the Protection System that operated is not directly associated with maintenance, testing, inspection, construction or commissioning activities. **Response:** Replacing "is unrelated to on-site" in category 6 of the definition removes the implication that these activities were actively being performed. The inadvertent operation of transfer trip during "on-site" activities is excluded from being considered a Misoperation. The Application Guidelines before and after Example 6d has been revised to emphasize this point. Change made. 3) Add an Application Guideline example showing that transfer trip testing would not be considered Misoperation as well. Even though the BES interrupting device is at a different location than the testing error, the transfer trip composite system is involved. We suggest: "An operation that occurs during a non-fault condition but was initiated by remote transfer trip system maintenance, testing, inspection, construction or commissioning activities is not a Misoperation." **Response:** See Example 6d which was added to the Application Guidelines. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Georgia Transmission Corp	Yes	6. Unnecessary Trip - Other Than Fault: ...is not intended to operate. An Operation caused by on-site maintenance, testing, inspection, construction or commissioning activities on the designated Protection System are not considered as a Misoperation. alternatively: ...is not intended to operate. Operation of a Protection System that is not the focus of on-site maintenance, testing, inspection, construction or commissioning

Organization	Yes or No	Question 1 Comment
		activity is considered a Misoperation. Suggested to highlight the second sentence in the 4th paragraph for defintition 6 in the Application Guidelines.
Response: The drafting thanks you for your comments and declines to make the suggested change since it does not add clarity. No change made.		
City of Tacoma, Tacoma Public Utilities	Yes	Is mechanical failure of an interrupting device during a fault a mis-operation? (The interrupting device is not part of the Protection System.) **Response:** No, a mechanical failure of an interrupting device is not considered a Misoperation since the interrupting device is not part of the Protection System. No change made. Is inappropriate operation of a relay that operates upon mechanical inputs a mis-operation? For example, what if the relay causes a trip when it should have restrained? **Response:** If the mechanical input is not part of the Protection System it is not a Misoperation. Special Protection Systems (SPS) are not applicable to this Standard. If the mechanical input is part of the Protection System, like an incorrectly set selector switch on a relay, then the operation would be considered a Misoperation. Your example indicates that the mechanical inputs are status points that are used to restrain operation. If these status points are not indicating properly because of a personnel error (e.g., wrong switch position), a problem with a switch, or faulty contacts and a false operation occurs, then it is a Misoperation unless the operation occurred during on-site maintenance. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Southern Company - Southern Company Services, Inc.;	Yes	Southern Company supports the SERC comments and are including the following additional comments:

Organization	Yes or No	Question 1 Comment
Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		1. We believe that the same consideration of whether or not the composite Protection System operated as intended could be addressed with a much simpler definition:"The failure of the Protection System to operated as intended, including failing to trip when it should have, unnecessarily tripping with it should not have, or tripping more slowly than intended." This definition allows the Protection System owner to evaluate the operation and determine if it operated appropriately. **Response:** Although a simpler definition has advantages, it has significant shortfalls. For example, by using the word “when” it is not clear whether an operation is a Misoperation if it was slow or just whether it did or didn’t operate. The proposed definition does not achieve the clarity that the specific exceptions in the six categories provide. No change made. 2. We believe that the shift in focus to "composite" and "overall performance" does not clarify the ability to identify misoperating Protection System components. **Response:** The standard proposes a new definition for “Composite Protection System to clarify what is in scope when reviewing Protection System operations. The word “overall” has been removed as it is subjective and not necessary with the inclusion of the proposed Composite Protection System definition. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Colorado Springs Utilities	Yes	
Northeast Power Coordinating Council	Yes	
Mary Jo Cooper	Yes	
ISO RTO Council Standards Review Committee	Yes	

Organization	Yes or No	Question 1 Comment
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	
Operational Compliance	Yes	
ITC Holdings	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
American Transmission Company, LLC	Yes	
Tri-State G&T	Yes	
Wisconsin Electric Power Company	Yes	

Organization	Yes or No	Question 1 Comment
Madison Gas and Electric Company	Yes	
Exelon Corporation and it's affiliates	Yes	
Sacramento Municipal Utility District	Yes	
Idaho Power Company	Yes	
Northeast Utilities	Yes	
Kansas City Power & Light	Yes	
CenterPoint Energy	Yes	
Public Utility District No. 1 of Snohomish County	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Nebraska Public Power District	Yes	
Oncor Electric Delivery Company LLC	Yes	
Hydro-Québec Procution	Yes	

Organization	Yes or No	Question 1 Comment
Los Angeles Department of Water and Power	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	
Seminole Electric		The NERC STD defines a Slow Trip as a "Protection System operation that is slower than intended... ." (emphasis added). My preliminary read of this language was that if the Protection System operated slower, i.e., took even 1 cycle longer in time to operate, than how it was intended to be set, that such delay would be a Slow Trip. However, reading your responses to comments, it appears that "time" is not the measure of compliance, but in fact, the compliance metric is based on intended protective objective. By this I mean, if the overall goal of protection is met, then there is no slow trip no matter how much time has passed. To clarify even more, so as long as no additional harm has occurred during the time delay, time is not the measurement for compliance, but harm to the protected equipment is the compliance measure. With that said, can you please describe in some more detail how this compliance metric, i.e., additional harm, will be documented and audited?
Response: The drafting team thanks you for your comments. The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). No change made. The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its		

Organization	Yes or No	Question 1 Comment
Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made.		

2. ***Requirement R1 was revised to to provide more clarity regarding the responsibilities of the BES interrupting device owner and the Protection System owner (if they are different entities) when a Protection System operation occurs. Do you agree with these changes? If not, please provide specific suggestions for improvement.***

Summary Consideration:

The following resulted in a revision to the proposed standard. This first summary response addresses the majority comment which accounted for at least 16 comments represented by 63 individuals and a change to the proposed standard. Stakeholders raised issues about the lack of clarity concerning who had responsibility under Requirement R1. To resolve this, the drafting team revised Requirement R1 to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation.

Also resulting in a change to the proposed standard, approximately six comments supported by 11 stakeholders had concern about initiating the review for Misoperation based on the operation of the BES interrupting device. The drafting team noted that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). And that the BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity.

The drafting team revised the standard based on at least two comments represented by 27 stakeholders that were concerned about working cooperatively when the Protection System is jointly owned. The drafting team clarified that the notification starts the period for the Protection System component owner to begin its investigation. More importantly, having the BES interrupting device owner "officially notifying" other Protection System component owners when there may be no need to do so, will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner's Protection System component(s) caused a Misoperation. The requirements do not preclude the entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to clarify that the BES interrupting device must make notifications (now R2) when Protection System component(s) did not cause the BES interrupting device(s) operation.

The use of "BES interrupting device" was raise in at least two comments representing 13 stakeholders. The drafting team clarified the use of "BES interrupting device" in the standard's Application Guidelines under the "Definitions" section.

About five comments supported by individual stakeholders expressed concern about the action plan which resulted in a revision to the proposed standard. The standard now provides the entity a periodic time frame for continuing its investigation into the cause of the Misoperation beyond the 120 calendar day period. This also replaced the previous Requirement for having an "action plan" and is now addressed by Requirement R4.

The phrase "slower than required" means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made.

Last, a few comments by stakeholders led to revising the Measures. Only one comment resulted in the drafting team including a suggestion to incorporate the "manual intervention" due to a BES Protection System failure to operate into Requirement R1 to address a failure to trip. The drafting team responded to this single minority comment recognizing that the condition is possible and has adequate merit to be included in the requirement.

The following did not result in a change to the proposed standard. The remaining text summarizes industry concerns that did not result in a change to the proposed standard. Approximately seven comments supported by at least 40 stakeholders were concerned that the standard unnecessarily places entities a risk of a violation should they miss the review period due to natural disasters or some other unusual circumstance. The drafting team responded that the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur and does not benefit the standard overall.

At least one comment representing about eight individuals suggested the standard lean more toward performance objectives to remove ambiguities and judgment concerns (e.g., slow trips). The drafting team continues to support the proposed standard as currently structured noting that the draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities.

Another single comment supported by eight stakeholders was concerned about what to do when there is a lack of information to determine whether a Misoperation occurred or not. Although this did not result in a change to the proposed standard, the drafting team noted that an entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity could judge the operation was correct. No change made.

Two single comments that did not result in a revision to the proposed standard were concerned with how to review Protection System operations. The drafting team responded that the construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES.

A single minority comment was concerned about which entity would report for jointly owned Protection Systems where each entity had a Misoperation cause. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) specify the Protection System owner that caused the Misoperation will report.

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	No	R1 and the rationale for R1 assume that the BES interrupting device owner and the Protection System owner have been talking and R1 requires identification and review of each operation within 120 days. R1 should require that the BES interrupting device owner notify the Protection System owner or vice versa, depending on which entity discovers the event first, within a specific time after the entity is aware of the operation in order to ensure that the other entity has adequate time within the 120 day period to finish the review.

Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of

Organization	Yes or No	Question 2 Comment
the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.		
Bonneville Power Administration	No	(1) The changes made to R1 are an improvement over the previous draft, but they still do not adequately clarify the responsibilities. Both the Rationale for R1 (blue box) and the Application Guidelines indicate that the responsibility to investigate operations is placed on the owner of the interrupting device. However, BPA believes that the actual wording of R1 does not necessarily place the responsibility on the owner of the interrupting device. Instead, R1 places the responsibility on the TO, GO, or DP which has an interrupting device operation in its facility. Since it is quite common in the industry for TOs, GOs, or DPs to own interrupting devices within another entity's facility, R1 will sometimes place the responsibility on the owner of the facility where the interrupting device is located instead of on the owner of the interrupting device. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. In addition, the bullet points of R1 address the cases where the entity owns both the interrupting device and the protection system and where the entity owns the interrupting device but not all of the protection system, but there is no bullet point to address the case where the entity owns the protection system but not the interrupting device. It is not unusual for the owner of a facility to own a protection system but not the interrupting device that is operated by the protection system. Because it is vital that there is no ambiguity about who is responsible to initiate the investigation when an interrupting device operates, BPA recommends that the responsibility be placed on

Organization	Yes or No	Question 2 Comment
		the owner of the protective relays which caused the interrupting device to operate because the owner of the protective relays will have access to the primary information that will determine how the investigation should proceed. After the owner of the protective relays makes an initial investigation, the owners of the interrupting device or the owner of other components of the protection system can be notified to investigate their part of the protection system. If the responsibility to initiate the investigation is placed on the owner of the interrupting device, that entity will have to immediately turn to the owner of the protective relays to start the investigation. **Response:** According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made. (2) The use of Facility as defined by NERC in Requirement 1 does not make sense. As used in Requirement 1, Facility seems to indicate a substation or switching station, which is not in agreement with the NERC definition, which is a set of equipment that operates as a single element. BPA recommends that Facility not be used in Requirement R1 to avoid this problem. **Response:** Requirement R1 was revised to remove the use of "Facility." Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
ACES Standard Collaborators	No	(1) Also it is still unclear who has the ultimate responsibility for identifying and reviewing each operation if the interrupting device and Protection System are owned by two or more parties. What should occur if there is disagreement over the responsibility or the ownership of a component? What if multiple parties owned

Organization	Yes or No	Question 2 Comment
		components that contributed to an operation or a Misoperation? Are both parties responsible? The rationale may provide additional guidance, but the words in the requirements are unclear. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. According to the standard, each entity has an independent responsibility to identify a Misoperation of its Protection System components, if any, beginning with the BES interrupting device owner through any notified Protection System owner. Change made. (2) "BES interrupting device" is not a defined term and is vague and ambiguous. We understand that devices that interrupt fault current, such as circuit breakers and circuit switchers would be included but what other devices such as motor operated disconnects? Are they not included because they don't interrupt any current? What if they are equipped to interrupt charging and load current? Failure to define "BES interrupting device" could result in an informal definition that results in inconsistent enforcement by including components outside of the scope of what is intended to be a BES interrupting device. This term adds uncertainty and creates opportunities for multiple interpretations. **Response:** The use of "BES interrupting device" has been clarified in the standard's Application Guidelines under the "Definitions" section. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Independent Electricity System Operator	No	1 We belive that R1 should be written more clearly, by saying that: "Within 120 calendar days of a BES interrupting device operation casued by a Protection System operation, each Transmission Owner, Generator Owner, or Distribution Provider - that owns the BES interrupting device - shall identify and review each Protection System Operation."

Organization	Yes or No	Question 2 Comment
		Response: Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. 2 Also, there is a lack of clarity on which entity is responsible for developing and implementing a Corrective Action Plan. We believe that there has to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible for the CAP, especially in view of the rationale provided in the text box for R1, whose excerpt says: "The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3". We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest revising the leading part of R2 to: "Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying....". The Same revision should apply to R3, as follows: "Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of the associated BES interrupting device operation,....." Further, though not explicitly stated, we assume that the owner of the component that

Organization	Yes or No	Question 2 Comment
		contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4. **Response:** The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	1. The requirement R1 can be simplfied by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. 2. The notification and response requirement of R1 is not needed, as the owner of the Protection System that operated is already required to investigate each operation in Requirement R1. An additional requirement for notifications and responses is superfluous. **Response:** Notification is necessary to require other owners of the Protection System

Organization	Yes or No	Question 2 Comment
		components to review their Protection System components for Misoperation. Notification and requirements for other owners have been removed from Requirement R1 and replaced by Requirements R2 and R3, respectively. Change made. 3. There is a timing problem with R1.2 for the protection system owner who is notified on day 119 following a protection system operation. It is not reasonable or just to require this protetion sytem owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a misoperation of another entitiy's protection system. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Electric Power	No	AEP recommends the following modification to 1.1: "Within 120 calendar days of a BES interrupting device operation in its Facility caused by a BES Protection system operation or by manual intervention due to a BES Protection System failure to trip, identify and review each BES Protection System operation and BES Protection System failure to trip." **Response:** This suggestion has been incorporated into Requirement R1 to address manual intervention due to a BES Protection System failure to operate. Change made. AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs near the end of the 120 day period, and the notified entity does not have sufficient time to determine if their component operated properly or

Organization	Yes or No	Question 2 Comment
		misoperated within the 120 day period. AEP requests the standard be modified to clarify the liability of the notified entity if the notification occurs more than 180 days after the BES interrupting device operation. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. AEP requests that R1 should be modified to clearly indicate whether the term "entity" includes separate Functional Entities within the same Registered Entity. As written, it is unclear if the Transmission Owner function is required to notify the Generator Owner function within the same Registered Entity for compliance with R1.1 Bullet 2 or if the Registered Entity with multiple Functional Entities is treated as a single unit for ownership purposes. **Response:** The use of "entity" following the first use of the applicable entities (e.g., Distribution Provider, Generator Owner, and Transmission Owner) in the requirement is clear by the construction of the requirement. No change made. R1.2 appears to add little value as a standalone requirement. AEP recommends removing R1.2. and incorporating the requirement to identify a cause within the remaining R1 and R3 wording. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s)

Organization	Yes or No	Question 2 Comment
		operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Transmission Company, LLC	No	ATC believes that the investigation for relay misoperation should be performed by the owner of the initiating relay as opposed to the interrupting device owner for the following reasons: By definition, "Circuit breaker and other interrupting device mechanisms are not part of a Protection System". As such, PRC-004 should not require the interrupting device owner to be responsible for R1. PRC-004 is based on Protection System operation, not breaker operation. Bus design can have multiple breakers owned by different entities but the ownership of the initiating relay is clear. The BES interrupting device owner lacks the information that the protective relay owner has to be able to perform a root cause analysis of a misoperation.
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.		
City of Austin dba Austin Energy	No	Austin Energy agrees with Luminant's comment and copies it here for convenience. Requirement R1 requires all BES interrupting device operations be reviewed within 120 days. Under the Application Guidelines (Definition of a Misoperation - item 6 (page 17)), reverse power relaying used for normal unit shutdown is excluded. We recommend that this clarification be included in the Standard; either in language in the

Organization	Yes or No	Question 2 Comment
		Definition of a Misoperation (items 2, 5, and 6) or in Requirement R1.
Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), "Primary motoring protection is provided by reverse power relays for all unit types." Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay's use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.		
CenterPoint Energy	No	CenterPoint Energy is concerned the wording of R1.1 to review a BES interrupting device "operation" within 120 days and the wording of R1.2 to investigate a "misoperation" within the same 120 day period of a BES interrupting device operation could be unworkable. The owner of the BES interrupting device could notify the owner of the Protection System component identified as contributing to the Misoperation well into the 120 day period, which would give the Protection System component owner little time to investigate and determine a cause. CenterPoint Energy recommends R1.2 wording be the following: "The owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified, by the latter of 120 days of a BES interrupting device operation or 30 days after receiving notification from the owner of the BES interrupting device."
Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.		
Florida Municipal Power Agency	No	First, as currently drafted, R1 means that each investigation into a protection system operation is auditable, which in turn means that the definition of misoperation as

Organization	Yes or No	Question 2 Comment
		discussed in question 1 need to be easily measurable. Please see discussion in question 1 about the difficulty in measuring: 1) “slower than intended”; 2) whether or not a Fault occurred; and 3) whether or not that Fault was “within the zone it was designed to protect”. **Response:** The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation was adequate. The intent is not to require documentation of exact Protection System operation times; however, each entity must determine what evidence it needs to support compliance with the requirements. The definition of Misoperation has been revised to clarify slow trips and additional detail added to the Application Guidelines. Change made. Second, there are numerous Protection System operations wtihin a year, which results in a high-volume problem similar to those found in CIP standards, COM-003 and PRC-005. FMPA continues to recommend, as we did last time, that this standard would be better served by instituting internal controls language for R1 similar to what the CIP v5 and COM-003 SDTs adopted. Adopting such language would have the additional benefit of allowing the entity more latitude for how they deal with the ambiguities described in response to question 1. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No

Organization	Yes or No	Question 2 Comment
		change made. Third, FMPA commented last time that there ought to be an exception for Acts of Nature such as hurricanes and other natural disasters with, at minimum, the 120 day rule being waived. In response to FMPA's comments, the SDT agreed with this concern. However, rather than change the standard, the response was: "The drafting team agrees with your comment about instances when major disturbances occur. As noted in the Guidelines and Technical Basis section of the standard, in the event of such natural disasters, the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 includes the provision that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard." That means that the entity would still be in violation of the standard if it were not able to investigate all relay operations that occurred dueing a natural disaster. This is not acceptable to FMPA and we desire language to extend the time of the investigations as a result of Acts of Nature (e.g., a named storm, an earthquake that resulted in severe damage, etc. - maybe anytime a State's Governor declares an emergency) to a longer hodl th entity to the 120 day time period, e.g., but instead to a longer period such as 240 days, to allow time for more pressing disaster recovery efforts, without actually incurring multiple violations to the standard that would remain on the entities "record". **Response:** The *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made. Fourth, there is no recognition that it is possible to have a condition where it cannot be determined whether the operation was correct or a Misoperation, e.g., if the location

Organization	Yes or No	Question 2 Comment
		of the fault cannot be determined, or whether a fault condition actually existed or not, especially for something like a trip with successful reclose. See the second point made in response to question 1 for further discussion. **Response:** Although it is true that it may be difficult to precisely locate a Fault, it is incorrect to consider that these events are indeterminate. As proposed in the PRC-004-3 standard, an entity is not required to precisely locate or find residual evidence of Faults nor is an entity required to install Disturbance Monitoring Equipment (DME). See Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018) for requirements concerning DME. In regards to the default assumption, an entity should review the documentation it can obtain for an event, and if there is no evidence of a Misoperation, then the entity should document the operation was correct. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Hydro-Québec Procution	No	In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that occured on the BES have to be done, even if the event do not affect the reliability of the BES.
Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.		
PacifiCorp	No	In the second draft of PRC-004-3 PacifiCorp commented that the 120-day time limit in R1 is insufficient. PacifiCorp maintains that when two registered entities are involved in the interrupting device operation, 120 days is not enough time for both entities to complete the activities required by the requirement. PacifiCorp proposes an increase

Organization	Yes or No	Question 2 Comment
		of 60 days for each entity to complete their respective activities in sequence. This would increase the total from 120 to 180 in R1.

Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.

Organization	Yes or No	Question 2 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration agrees that the owner of the tripping device should own the investigation and bring in other entities as needed. In addition, R1 takes out any guesswork about the responsibilities of each Protection System owner who may have contributed to the Misoperation. What we still do not understand is the recourse available to the Protection System owner if the request for assistance from an adjacent entity is sent late. The requirement does not account for the fact that a notification may be issued weeks after the fact - the 180 day assessment deadline applies regardless. Under these circumstances, the recipient may be forced to declare that a cause was not found, as allowed by R3, and develop an action plan to investigate further. However, this leaves that owner in the position to explain the delay to auditors; which we do not believe is appropriate. Even more concerning, there appears to be nothing that stops the CEA from deciding that the reduced interval was adequate and assessing a violation as a result.

Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection

Organization	Yes or No	Question 2 Comment
System component(s) caused a Misoperation. Change made.		
Wisconsin Electric Power Company	No	It is not appropriate to make the owner of the interrupting device responsible to investigate Protection System operations. Interrupting devices as such are not components of a Protection System as defined by NERC. Responsibility for this investigation should be solely with the owner of the Protection System initiating the operation, and/or the owner of the Protection System which failed to operate.
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.		
Lincoln Electric System	No	LES recommends additional clarification be provided regarding the statement in R1.1 to “identify and review each Protection System operation”. As currently written, it is unclear how an entity would comply with R1.1 in the event that an incident involves multiple breaker operations with automatic reclosing, but were the result of a single cause. In such a scenario, would the entity be required to maintain separate documentation for investigation, designation, etc for each breaker operation?
Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.		
Colorado Springs Utilities	No	Please consider clarification of the terms “BES Protection System”, “Protection System”, “BES interrupting device” and “interrupting device” throughout the proposed

Organization	Yes or No	Question 2 Comment
		standard. Specifically in R1.1 the proposed requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. The wording of this requirement infers that the proposed standard is intended to include investigation of non-BES protection systems that cause the operation of a BES interrupting device. While such investigation is sound business practice, it may be outside the intended scope of the standard. An example would be the operation of a load serving transformer (say a 230kv to 13.2 kv unit) differential Protection System that operates both a BES interrupting device (a 230kv circuit breaker) and a non-BES interrupting device (a 13.2kv circuit breaker). The stated purpose of this standard is to “Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems” and is supported by the terminology used in the opening paragraph of the Background statement and the content of the Compliance section. Operation of a load serving facility protection system normally will have no impact on the reliability of the BES unless its failure to operate results in a subsequent operation of a BES bus differential Protection System or BES transmission element Protection System, for example. A similar argument can be offered for operation of protection system on non-BES radial lines and local network that cause operation of a high-side interrupting device which may also be part of a BES Protection System. Based on this line of thinking, it is proposed that the wording of requirement 1.1 be revised to state “Within 120 calendar days of an interrupting device operation in its Facility caused by a BES Protection System operation, identify and review each BES Protection System operation.” The wording of Requirements R1.2 and R3 should also be modified for consistency.

Response: The drafting team thanks you for your comment. The occurrences of “BES Protection System” have been revised to

Organization	Yes or No	Question 2 Comment
pertain to Protection Systems for BES Elements. The use of "BES interrupting device" has been clarified in the standard's Application Guidelines under the "Definitions" section. Change made.		
Los Angeles Department of Water and Power	No	Please see answer to Question 5
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Madison Gas and Electric Company	No	Please see question 5.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Public Service Enterprise Group	No	R1 addresses the situation where a BES interrupting device operation may be the result of the operation of a Protection System operation owned by an entity that does not own the BES interrupting device. As written, the owner of the BES interrupting device has no deadline to notify the owners of other Protection Systems when cannot determine that the Protection System operation was correct (the second bullet in Part 1.1). R1 presently allows 120 calendar days in total for the owner of the BES interrupting device to notify the other Protection System owners and for those other owners to determine if their Protection System operated correctly and if they did not, to document each Misoperation, including a cause if one can be identified. As drafted, the owner of the BES interrupting device could notify the other Protection System owners on the 119th day following the operation of its interrupting device, making it impossible for those other Protection System owners to perform their required analysis by the 120th day. The change identified to Part 1.1 below requires the owner of the BES interrupting device to make a notification to the other Protection System owners within 60 calendar days of the operation of its BES interrupting device if the situation described

Organization	Yes or No	Question 2 Comment
		above occurs. The changes to Part 1.2 below allows either Protection System owner 90 calendar days to document the findings of each Protection System Misoperation that may have occurred, making the total number of days allowed from the date of the operation of the BES interrupting device 150 calendar days. Only 30 calendar days has been added to the timeline, but this additional 30 days is needed to correct the potential inequity for owners of Protection Systems that do not own the BES interrupting device to complete their analysis. For consistency, 30 calendar days was added to the R3 timeline of 180 days, making it 210 days from the date of the operation of the associated BES interrupting. R2 is unchanged, but is shown for completeness. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. We have also added a provision in a footnote that allows a Regional Entity to extend deadlines that are referenced to the operation date of a BES interrupting device for instances such as natural disasters. Personnel that might normally evaluate the operation of a Protection System may not be available to do so due to their involvement in restoration efforts. Here is our suggested changes. Additional language is CAPITALIZED. R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]1.1 Within [delete "120"] 60 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review

Organization	Yes or No	Question 2 Comment
		each Protection System operation AND [FOOTNOTE 1];. If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation, OR; If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. FOOTNOTE 1: Such 60 day period and subsequent periods in the standard that have a deadline that references the operation date of a BES interrupting device may be extended by the Regional Entity for instances such as a natural disaster. 1.2 Within the same [delete "120 day period"] 150 CALENDAR DAYS of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified. R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability. R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within

Organization	Yes or No	Question 2 Comment
		180 210 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning] Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or A declaration explaining why no further actions will be taken. **Response:** The *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Northeast Utilities	No	R1.1 second bulleted item states: If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information. The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component. This requirement statement is confusing and should be revised to clearly describe the intent. Additionally, this statement requires action by more than one entity within the 120 day time period. There is no requirement for BES interrupting device owner to

Organization	Yes or No	Question 2 Comment
		notify the owner of the protection system component identified as contributing to the misoperation prior to 120 days which could leave the protection system component owner no time to investigate and determine if the operation was correct or not as required in R1.1 and determine the cause as required in R1.2 (which also must be completed within the first 120 days). We suggest that the above statement be a separate requirement under R1 and be worded as follows: If the BES interrupting device owner cannot determine that the Protection System operation was correct, and concludes that protection system components owned by another entity contributed to a possible misoperation, the BES interrupting device owner shall notify the other owner(s) of the Protection System component(s) of their preliminary conclusions and provide any requested investigative information within 90 days of an interrupting device operation. It is suggested that a 90 day timeframe for this situation is still reasonable for the interrupting device owner and allows 30 days for the owner(s) of the Protection System component(s) to comply with the existing R1.1 and R1.2.During the 120 day review period, requirement 1.1 does not ensure that there will be adequate time for ALL Protection System owners to review the operation. If the BES interrupting device owner is tardy in informing another Protection System component owner, then that Protection System owner may not have time to perform a review. There should be some milestone within the 120 day review period where all Protection System owners need to be informed of the operation and their need to review it.
Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.		
Pepco Holdings Inc & Affiliates	No	Requirement R1 places the responsibility on the BES interrupting device owner to

Organization	Yes or No	Question 2 Comment
		investigate all operations initiated by a Protection System which trips the interrupting device. We vigorously disagree with this assignment of responsibility. The responsibility for R1 through R4 should be on the owner of the Protection System which initiated the tripping of the interrupting device, not the owner of the interrupting device. All previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. Therefore, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device. The entity who owns the interrupting device is not necessarily the one who owns the Protective System. For example, it is not uncommon for a generator to be interconnected to a TO switchyard, where the TO owns the breakers (interrupting devices) in the switchyard but the GO owns the Protection Systems protecting his generator unit. The GO Protection Systems trip the TO's breakers to isolate the unit from the system. The way the present standard is written the TO would be responsible for reviewing and identifying all GO protection initiated trips just because the TO owns the interrupting device. This is totally unreasonable. In a power plant, when a generator unit trips off line due to a plant Protective System operation lockout relays are employed to prevent re-energization of the unit until the cause of the trip can be determined. When this occurs, the investigation of this event should be initiated and pursued solely by the GO (i.e. the owner of the protective system that caused the tripping of the BES interrupting device) and not by the TO, who may happen to own the interrupting device. The GO may request data and information from the TO to assist in their investigation, however, all compliance responsibility for reviewing operations and identifying misoperations should solely rest on the owners of the Protective System(s) that initiated the trip of the BES facility (in this case the GO). In this case, involving the TO solely because they are the owner of the interrupting device places an unwarranted compliance burden on the TO. Although the TO may be aware that the interrupting device opened, they are not is a position to determine if it was

Organization	Yes or No	Question 2 Comment
		opened due to a plant Protective System operation, or was opened due to a manually initiated trip of the unit as it was being taken offline, since the GO, rather than the TO, usually has operational control over these breakers. In order to properly assign compliance responsibility to the appropriate entities, and eliminate the unwarranted compliance obligation on the interrupting device owner, we would suggest re-wording R1 in either one of two ways: OPTION 1 - Preferred: (assign responsibility to each Protection System owner rather than to the interrupting device owner) R1.1 "Within 120 calendar days of the operation of an interrupting device(s) which interrupts a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, each Transmission Owner, Generator Owner, and Distribution Provider, who owns a Protective System which is connected to trip the interrupting device(s) shall review the event to determine if their Protection System operation was correct, or a misoperation." With the above language the responsibility is clearly and properly assigned to the owner(s) of the Protective System(s) which initiated the tripping. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. While retaining this approach for shared Protection Systems the remaining Parts of Requirement R1 will also need to be re-worded to remove references to the interrupting device owner. OPTION 2 - Alternate: (replace owner of the interrupting device with owner of the interrupted BES Facility)

Organization	Yes or No	Question 2 Comment
		R1.1 "Within 120 calendar days of the interruption of a BES Facility (i.e., line terminal, transformer, generator unit, etc.) that was caused by a Protective System operation, the Transmission Owner, Generator Owner, and Distribution Provider, who owns the Facility that was interrupted shall identify and review each Protective System operation. If the entity owns both the BES Facility and the Protective System, determine if it was a correct operation, or a Misoperation. If the entity owns the BES Facility but does not own all of the Protective System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protective System component(s) and provide any requested investigative information. The Protective System component owner(s) that was notified by the Facility owner shall determine if there was a correct operation or a Misoperation of their component. 1.2 Within the same 120 day period of the interruption of a BES Facility caused by a Protective System operation, the owner of the Protective System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified." The above language is consistent with the way TADS and GADS data is entered (i.e. by the Facility Owners). In addition, the Protective System(s) which protect and trip a specific Facility are almost entirely owned by the owners of the Facility. This Option adequately addresses the example raised previously, eliminating the need to involve the TO for generator initiated trips. The only complication arises when dealing with transmission lines terminating between two separate companies. The line terminals at each end may be owned by each respective company but the line itself may be entirely owned by only one company. To overcome this deficiency, this proposed re-write of R1 uses the term "line terminal" in the parenthetical list of BES Facilities. This would make the owners of the Protective Systems on each respective line terminal responsible for the review and analysis of their systems rather than the owner of the line itself.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.		
ReliabilityFirst	No	Requirement R1 relies on the operation of an interrupting device and the identification by its owner that a Protection System operated and further that it may have operated due to a Misoperation. There are two issues with using this as the focal point of the actions within the standard. 1) First, the owner of the interrupting device may not be in the best position to decide why the device operated, if a Protection System was involved and if a Protection System component contributed to a Misoperation. This partly is because the interrupting device excluding its trip coils and CTs is not part of the Protection System. The owner of the relay that activated the trip or the owner of the associated Disturbance Monitoring Equipment would be in a much better position to evaluate the operation. The requirement circumvents what may be a natural process of investigating the operation by its individual owners separately or collectively. The requirement may create a weak link in a chain because of its reliance on the interrupting device owner to start the identification and review process. 2) Second, not all Misoperations result in an interrupting device operation particularly if no Fault occurred or the Fault is a high impedance transient Fault. The owner of the Protection System that failed to operate would not be required to investigate it. 3) Finally, the requirement should be rewritten to obligate the owner of its Protection Systems to investigate their performance and to notify joint owners of their findings if they need to take follow up actions. Inserting the interrupting device owner unnecessarily into the process of investigation does not serve a reliability purpose but an administrative one.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.		
Texas Reliability Entity	No	See comments submitted in response to Question 5 below.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Sacramento Municipal Utility District	No	See response under Question #5 with specific recommendations to implement Internal Controls.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Public Utility District No. 1 of Snohomish County	No	See response under Question #5 with specific recommendations to implement Internal Controls.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Liberty Electric Power LLC	No	The "same 120 days" could place an impossible burden on an entity notified late in the 120 day period. Notification that an issue with an entity's system contributed to a misoperation should start a new compliance clock.
Response: The drafting team thanks you for your comment.Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td>Tennessee Valley Authority</td><td>No</td><td>The changed wording of R1 was an improvement. However, our concern comes from our company enduring a major natural disaster and the aftermath. When recovering from a major event such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes weeks and is not the top priority for a utility that endures such an event. The Standard needs wording to allow additional time when a utility endures a natural disaster.</td></tr>
<tr><td colspan="3">Response: The drafting team thanks you for your comment. The Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made.</td></tr>
<tr><td>Midwest Reliability Organization NERC Standards Review Forum (NSRF)</td><td>No</td><td>The NSRF believes there should be exception for Acts of Nature such as tornados, ice storms and other natural disasters with, at minimum, the 120 day rule being waived. In previous comments the SDT agreed with this concern but did not add this exception. A wide spread thunderstom with heavy lightning can set off multiple trips and recloses in a short time. There should be a process to excempt such events.

Please verify that reclosing relays are not within scope of this Reliability Standard.</td></tr>
<tr><td colspan="3">Response: The drafting team thanks you for your comment. The Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: “In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties.” While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made. Presently reclosing relays are not part of the definition of Protection System thus are excluded from the scope of this standard. No change made.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The Protection System component owner who does not also own the interrupting device may be placed in a non-compliant situation through no fault of their own. Their compliance is contingent upon a timely notification from the owner of the BES interrupting device. If the notification is not made in a timely fashion to allow for investigation the Protection System component owner would be non-compliant for not conducting an investigation and documenting the findings within 120 days. For this situation the BES interrupting device owner should have an abbreviated time frame to notify the Protection System component owner to provide sufficient time to collect the appropriate information and investigate the operation. Conversely, the owner of the Protection System component could be granted more time to investigate (i.e. 120 days from the notification by the BES interrupting device owner). **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. A misoperation investigation if Protection Systems are shared between two or more entities is often a joint effort. The Application Guide clearly defines that "it is expected that both entities will work together to investigate the cause of the operation", which is desired. This is not clearly defined in R1 and should be clarified. The Application Guide should indicate that this notification should be done as soon as possible. **Response:** Notification starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner's Protection System component(s) caused

Organization	Yes or No	Question 2 Comment
		a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to move notification into a separate new Requirement now R2. This requirement clarifies that the BES interrupting device must make notifications when (1) it share components of a Composite Protection System, (2) it determined a Misoperation or cannot rule out a Misoperation, and (3) its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
PPL NERC Registered Entities	No	The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. There is a possible time coordination issue for identification and review of misperations with R1.2. As stated in the proposed standard, R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. If timely communication of misoperation information is delayed by a Protection System component owner, the BES interrupting device owner could possibly bear the responsibility of not meeting the 120 day reporting requirement per R1. Fundamentally, R1 frames the time period for reviewing and analyzing a misoperations where multiple responsible entities are involved. However, R1 does not take in to account that one entity’s analysis may be dependent upon the other’s final analysis and that parallel review of misoperations are not possible. More consideration should be given to the cases where one entity’s actions impact another’s ability to meet the requirements of R1.However, concur in overall concept with clarifying coordination roles between BES interrupting device owner and the Protection System owner.
Response: The drafting team thanks you for your comment. Requirement R1 was split into two separate Requirements (R1 and R3) to		

Organization	Yes or No	Question 2 Comment
provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.		
Essential Power, LLC	No	The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame. There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. **Response:** The Measure has been revised for clarity and to be more concise. Change made.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Cogentrix Energy Power Management, LLC	No	The requirement R1 can be simplified by wording it in this manner: "Each entity shall identify, review, investigate, classify, document, and, for misoperations, determine the cause (if identified) of each Protection System operation that they own..." by the required time frame.There is a timing problem with R1.2 for the Protection System owner who is notified on day 119 following a Protection System operation. It is not reasonable or just to require this Protection System owner to complete the requirements of R1 in one day's time after being notified by the owner of an interrupting device whose operation was suspected to be caused by a Misoperation of another entity's Protection System. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. **Response:** The Measure(s) have been revised for clarity and to be more concise. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Tallahassee	No	There should be some provision in the standard to take in to account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able

Organization	Yes or No	Question 2 Comment
		to perform an analysis within 120 days following a major disaster. **Response:** The *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made. Also, there are some circumstances when an investigation is out of the control of the entity. For example if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company it may take longer than 120 days to perform a thoroughly investigation. **Response:** The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Tallahassee - Electric Utility	No	There should be some provision in the standard to take into account extenuating circumstances such as natural disasters. It would be unfair to expect entities to be able to perform an analysis within 120 days following a major disaster. **Response:** The *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation

Organization	Yes or No	Question 2 Comment
		might occur. No change made. Also, there are some circumstances when an investigation is out of the control of the entity. For example, if a relay or protection device potentially failed but needed to be investigated by the manufacturer or an outside company, it may take longer than 120 days to perform a thorough investigation. **Response:** The standard now provides the entity a periodic time frame for continuing its investigation into the cause of a Misoperation. See the proposed Requirement R4. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Consumers Energy	No	There still seems to be a contradiction in R1 regarding the responsibilities of the BES interrupting device owner (IDO) vs. the Protection System owner (PSO) when owned by different entities (as we commonly have on the 138 system). The breaker, other than the trip coils and CTs, is not part of the Protection System, so the responsibility to investigate operations initiated by a protection system should be with the PSO. NERC's response below to Q4 seems to agree with this (regarding documenting, CAP, and reporting), but R1 still places responsibility for investigation on the IDO. As a matter of fact, the Rationale for R1 added into draft 3 the statement "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System." When an interrupting device operates, logically the IDO would investigate why their device operated. As soon as the IDO finds out that the operation was initiated by a protection system (the situation described in R1) they should then only have to notify the PSO of the situation (the PSO may not be aware of a protection system operation). The IDO would not be in the best position to investigate, and should not be validating Protection System operations for the PSO. The seems to be mostly a contradiction of the wording in R1 vs. the Rationale section. If the Rationale is not included in the final version of the standard, I could probably

Organization	Yes or No	Question 2 Comment
		agree with the wording of the rest of it.
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made. Notification starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners, especially when there is little possibility that another owner's Protection System component(s) caused a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification. Requirement R1 has been revised to move notification into a separate new Requirement now R2. This requirement clarifies that the BES interrupting device must make notifications when (1) it share components of a Composite Protection System, (2) it determined a Misoperation or cannot rule out a Misoperation, and (3) its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure. Change made.		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	none
Entergy Services, Inc. (Transmission)	Yes	Since actual Misoperation data reporting will now be addressed outside of this standard, entity data communication requirements within this standard need to be consistent with respect to data reporting criteria. As an example, since there is no requirement for a contributing component entity owner to forward the required investigative and CAP data to the interrupting device entity owner, one would expect that reporting will be the responsibility of the Protection System contributing

Organization	Yes or No	Question 2 Comment
		component entity owner.
Response: The drafting team thanks you for your comment. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made.		
ISO RTO Council Standards Review Committee	Yes	There is a lack of clarity on which entity is responsible for developing and implementing a CAP. We agree with the revision to Requirement R1, but believe that there needs to be corresponding revisions to R2 and R3 to clearly indicate which entity needs to be held responsible, expecially in view of the rationale provided in the text box for R1, whose excerpt says: “The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3”. We interpret the quoted excerpt (above) to mean that the component that contributed to the Misoperation may not be owned (in full or in part) by the owner of the BES interrupting device. It follows that in such cases, the owner of the component that contributed to the Misoperation is responsible for complying with R2 and R3. If this interpretation is correct, then Requirements R2 and R3 are not clear as to which entity is held responsible. To clarify this, we suggest to revise the leading part of R2 to: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 60 calendar days of identifying....”. The Same revision should apply to R3, as follows: “Each Transmission Owner, Generator Owner, or Distribution Provider that owns the component that contributed to the Misoperation shall, within 180 calendar days of of the associated BES interrupting device operation,.....” Further, though not explicitly stated, we assume that the owner of the component that

Organization	Yes or No	Question 2 Comment
		contributed to the Misoperation is also held responsible for complying with R4 to implement and complete the CAP or action plan to accomplish all identified objectives. Hence, the same qualifier should also be added to Requirement R4.
Response: The drafting team thanks you for your comment. The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made.		
Georgia Transmission Corp	Yes	While reporting falls under 1600, should PRC-004 clarify which of the two should file the Misoperation?
Response: The drafting team thanks you for your comment. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made.		
Mary Jo Cooper	Yes	
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
City of Tacoma, Tacoma Public Utilities	Yes	
Dominion	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Operational Compliance	Yes	
Western Electricity Coordinating Council	Yes	
Rayburn Country Electric Cooperative	Yes	
Xcel Energy	Yes	
ITC Holdings	Yes	
Manitoba Hydro	Yes	
Tri-State G&T	Yes	
Exelon Corporation and it's affiliates	Yes	
Idaho Power Company	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
Public Service Company of New Mexico	Yes	

3. **The Measures and VSLs were revised to reflect changes to the requirements. Do you agree with these changes? If not, please provide specific reasons why not and alternative recommendations and justifications.**

Summary Consideration:

The following resulted in a revision to the proposed standard. Due to the significant changes to the proposed standard (e.g., removal of the action plan), the Violation Severity Levels (VSL) have been rewritten to align with the revised Requirements. The drafting team contends that the revisions to the Requirements have resulted in more understandable VSLs. Likewise, there were at least seven comments supported by about 57 individuals that suggested revisions to the Measures. The drafting team also revised the Measures to focus on evidence examples and to be more concise.

Approximately seven comments represented by 23 stakeholders expressed concern with the escalation values in the VSLs. Because the new version of the VSL Guidelines provides more flexibility in the intervals, the drafting team has responded by increasing the interval periods for Requirement R1.

Although summarized earlier, about three comments represented by at least 13 individuals were concerned about ambiguity with the time periods for completing its investigation. The proposed standard now provides the entity a periodic time frame for continuing its investigation into the cause of the Misoperation beyond the 120 calendar day period in Requirement R1, Part 1.4.

Also summarized earlier, at least two comments supported by about eight stakeholders expressing concern about the time period for an entity that is notified to review its Protection System for Misoperation. Requirement R1 was revised to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.

Several comments suggested minor editorial clarifications which were implemented by the drafting team.

The following did not result in a change to the proposed standard. The following did not result in a change to the proposed standard. Approximately two comments supported by eight individuals wanted to use percentages for determining the level of violations. The drafting team contends that a weighting factor (i.e., use of percentages) is the most practical for assessing violations for fixed quantities and not for the VSLs in this proposed standard.

Organization	Yes or No	Question 3 Comment
Ameren	No	(1) We disagree with the VSL escalation, for R1, R2 and R3, from Moderate to High to Severe at 10 days interval each.
Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.		
ACES Standard Collaborators	No	(1) The measures are not consistent with the revisions to the requirements. For instance, Requirement R1 requires the owner of the component that led to the Misoperation to identify and review its performance. However, the Measures require the applicable entities to have evidence without any statement regarding the ownership of Protection Systems or circuit breakers.
Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.		
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	1. The evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. **Response:** The Measure(s) have been revised for clarity and to be more concise. Change made. 2. The severe VSL for R1, R2, and R3 can be simplified by changing a few words in the first item of each requirement. For R1, change "...entity performed the actions in ... and 1.2 in more than 170..." to "...entity did not perform the actions in .... and 1.2 within 170 ...". This would allow the 2nd and 3rd items in the OR statement to be eliminated. For R2, change "entity developed a CAP, or a declaration .... R2, more than 90 ..." to

Organization	Yes or No	Question 3 Comment
		"entity did not develop a CAP or a declaration ...R2 within 90 ...". This would allow the second part of the OR statement to be eliminated. For R3, change "entity developed an action plan, or made a declaration ... R3, more than 230 ..." to "entity did not develop an action plan or make a declaration ... R3 within 230 ...". This would allow the second part of the OR statement to be eliminated. **Response:** The VSL have been extensively revised due to the revisions to the requirements. Change made. 3. The VSL should be have a weighting factor in the % of operations not analyzed (otherwise it is one strike and you're out and this could be one event out of many). Equal severity for 1/10 events is not just compared to 1/100 events. **Response:** A weighting factor (i.e., use of percentages) is practical for assessing violations for fixed quantities, because Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Electric Power	No	AEP recommends adjusting the time requirements specified in the VSL tables for R1, R2 and R3 to extend the timeframe for Moderate and High VSLs to 20 days, and eliminate the time requirement for the Severe VSL. Example: For R1, the Low VSL remains the same, Moderate becomes >150 to 170, High becomes >170 to 190, and Severe only applies when "The responsible entity failed to identify and review... ". **Response:** In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and

Organization	Yes or No	Question 3 Comment
		implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made. Measure M1 repeatedly lists the same evidence examples and AEP suggests simplifying the measure by stating "evidence for R1 may include but is not limited to...." followed by a single list of items. **Response:** The Measure(s) have been revised for clarity and to be more concise. Change made. The wording for the R4 VSL references failure to revise a CAP "as needed". This statement is very broad, may be subject to interpretation and should be clarified or removed from the VSL. **Response:** The VSL was modified to be consistent with the revised CAP implementation requirement and to clarify the violation is on the CAP that was not updated when actions or timetables changed. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Arizona Public Service Company	No	Agree with the other changes but VSL severity levels are spaced 10 days apart. It should be at least 30 days apart. It is not justifiable to go from Lower to Sever VSL for 22 days of delay (149 days to 171 days). There is no justification for such strict time lines.
Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.		
Tennessee Valley Authority	No	As per Req. 2 - CAP Devlopment is too stringent. Troubleshooting and determining which element could take longer than the time allowed in the VSLs. Under PRC-004-1

Organization	Yes or No	Question 3 Comment
		a 12 month time period was given to develop and implement a CAP. **Response:** The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made. Recommend a CAP not developed w/in 120 days or a declaration in accordance with Req. R3 (Lower VSL), CAP not developed w/in 120 days or a declaration in accordance with Req. R3 w/in 120 days or CAP declared in accordance with Req. R2 not implemented within 150 days (Medium VSL), CAP not developed w/in 150 days or a declaration in accordance with Req. R3 w/in 150 days or CAP declared in accordance with Req. R2 not implemented w/in 180 days (High VSL), CAP not developed w/in 180 days or a declaration in accordance with Req. R3 w/in 180 days or CAP declared in accordance with Req. R2 not implemented w/in 210 days. **Response:** In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
ISO RTO Council Standards Review Committee	No	As we noted in our comments in the previous draft, the VSLs should recognize that some relay misoperations place a greater risk/impact on the BES than others.
Response: The drafting team thanks you for your comments. A Violation Severity Level (VSL) is a measure of how badly did the entity violated the requirement which, in this case, applies to all Protection Systems for BES Elements. Providing a risk-based VSL would reward an entity (i.e., safe harbor) for failing to identify a Misoperation and correcting the cause for a Protection System that may have a lower risk to the BES. The objective of the standard is to identify and correct the causes of Misoperations of Protection		

Organization	Yes or No	Question 3 Comment
Systems for BES Elements. The Compliance Enforcement Authority will assess the circumstances concerning potential violations. No change made. As stated in response to your previous comments, the FERC-approved description of "Violation Risk Factor" is "Each requirement must have an associated violation risk factor (High, Medium, or Lower). The risk factor is one of several elements used to determine an appropriate sanction when the associated requirement is violated. The risk factor assesses the impact to reliability of violating a specific requirement." However, the NERC Sanction Guidelines state that "Violation Risk Factors are assigned to standards' requirements as indicators of the expected risk or harm to the bulk power system posed by the violation of a requirement by a typical or median entity that is required to comply. NERC or the regional entity may consider the specific circumstances of the violator to determine if the violation of the requirement in question actually produced the degree of risk or harm anticipated by the Violation Risk Factor. If that expected risk or harm was not or would not have been produced, NERC or the regional entity may set the Base Penalty Amount to a value it (i) deems appropriate and (ii) is within the initial value range set above pursuant to Section 4.1." The drafting team believes that the NERC Sanction Guidelines address your comment.		
Hydro-Québec Procution	No	In the previous version, the purpose has been centered on the reliability of the BES. The removal of that concept (reliability of the BES) implies the analysis of all the events that occurred on the BES have to be done, even if the event do not affect the reliability of the BES.
Response: The drafting team thanks you for your comment. The construction of Requirement R1 requires that each operation of a Protection System that causes a BES interrupting device operation must be reviewed to ensure that the Protection System responded correctly. An entity may choose to group operations by event; however, in the case of a single permanent fault caused an initial operation and a subsequent reclose and operation, all operations must be reviewed to determine if the Protection System responded appropriately. This achieves the objectives of the standard in ensuring correct performance of Protection Systems, as well as identifying and correcting the root causes of Misoperations which do affect reliability of the BES. No change made.		
Manitoba Hydro	No	M1 - DME is not defined. **Response:** The abbreviation "DME" is a NERC defined term and acronym in the NERC Glossary of Terms Used in NERC Reliability Standards. For clarity, the acronym has

Organization	Yes or No	Question 3 Comment
		been spelled out. Change made. M3 - What was the reason for removing the words at the end 'explaining why no further investigation or actions will be taken' - these words are helpful and should be retained. **Response:** The phrase was redundant with the Requirement. No change made. VSLs - R1 - Severe VSL - the final option in this column seems to suggest that you would need both a failure to notify the other owners AND a failure to provide any investigative information. It doesn't contemplate a situation where an entity may have notified the other owners but failed to provide investigative information. **Response:** The requirement to provide investigative information was removed from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Pepco Holdings Inc & Affiliates	No	Measure M1 requires evidence "that documents the date and time of each applicable interrupting device operation and indicates when each related Protective System Operation was reviewed." Based on our comments from Question 2 and proposed re-wording of Requirement R1, Measure M1 should also be revised to require evidence "that documents the date and time that each BES Facility was interrupted due to the operation of a Protection System and the date the Protection System operation was reviewed."
Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.		
PacifiCorp	No	PacifiCorp is concerned that the VSLs are not commensurate with the reliability risk of the associated violations. In many cases, the difference between a "Lower" and a "Severe" VSL is an arbitrary additional number of days during which the reporting or documentation requirement was not satisfied. The fact that a report is an additional

Organization	Yes or No	Question 3 Comment
		30 days late should not increase the VSL from “Lower” to “Severe.” A later report does not increase the likelihood of additional adverse impact to the BES. A registered entity’s failure to remediate a protection issue is much more critical. A more reasonable timeframe for the VSLs would be 20 days per severity level instead of the proposed 10 days. PacifiCorp recognizes that the drafting team has made this change for the “Lower” VSL in Draft 3, but the remaining VSLs still reflect the 10 day timeframe. **Response:** In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made. Moreover, in keeping with PacifiCorp’s comment under Question 1, the “Lower” VSL should be amended from 120 calendar days to 180 calendar days to allow each entity enough time to complete their respective activities before incurring a violation of the standard. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’ responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. **Response:** The standard now provides the entity an extended period for continuing its

Organization	Yes or No	Question 3 Comment
		investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Los Angeles Department of Water and Power	No	Please see answer to Question 5
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Kansas City Power & Light	No	R4 VSL wording is not clear as presently stated; "The responsible entity failed to revise a CAP or action plan as needed in accordance with Requirement R4." It might not be intended, however this wording implies that all CAP's must be revised and if not revised there is a compliance issue. The wording should state; "A CAP revision was needed in accordance with R4 and the responsible entity failed to make the revision."
Response: The drafting team thanks you for your comment. The VSL was modified to be consistent with the revised CAP implementation requirement and to clarify the violation is on the CAP that was not updated when actions or timetables changed. Change made.		
Flathead Electric Cooperative, Inc.	No	ramping up the violation level simply on the number of days that pass to complete the analysis does not seep appropriate for situations where the discovery may have been delayed in the first place
Response: The drafting team thanks you for your comment. In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. The standard now provides the entity an extended period for continuing its investigation of a potential Misoperation beyond the 120 calendar day period. See proposed Requirement R4. Change made.		

Organization	Yes or No	Question 3 Comment
Essential Power, LLC	No	See comments to question 2
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 2.		
Cogentrix Energy Power Management, LLC	No	See comments to question 2
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 2.		
Sacramento Municipal Utility District	No	The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Public Utility District No. 1 of Snohomish County	No	The current Requirements and their current approach are not supported as noted in the response in Question #5. As such the VSL and Measures cannot be supported.
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
PPL NERC Registered Entities	No	The VSLs are hard-wired to response/reporting timelines specified per R1-R3. Some consideration should be given to technical complexity and circumstance of the SPS Misoperation. **Response:** The VSLs assess time-based violations based on factors such as, the BES interrupting device operation, notification, and creation of the Corrective Action Plan (CAP). Requirements for SPS Misoperation analysis and corrective action are addressed in PRC-016, not this standard. No change made. The R1 evidence listing in M1 is unnecessarily duplicative. Measure M1 (and likewise all of R1) could be greatly simplified by stating that the required evidence for proving compliance with R1 may include, but is not limited to ...then list the items once. **Response:** The Requirement(s) and Measure(s) have been revised for clarity and to be

Organization	Yes or No	Question 3 Comment
		more concise. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Mary Jo Cooper	No	This Standard allows 120 days for the entity to investigate the operation. We do not feel that this activity warrants a severe violation factor if only 1 operation was investigated 50 days later. We agree that if an activity has a significant impact on the BES than the violation severity level should be higher. In this case, however, immediate action is not required and therefore we disagree with the severe violation penalty suggested by the drafting team. **Response:** In the previous posting, the drafting team followed the guidelines for VSL escalation that were in effect at the time. However, the current version of the Violation Severity Level Guidelines provides more flexibility in the interval. Based on comments received, the drafting team increased the interval for Requirement R1 (including the new R2 and R3) severity levels to 30 days for the Lower VSL and 15 calendar days for the Moderate and High VSL. The interval for creation and implementation of the CAP in Requirements R5 and R6 (previously R2 & R4) have been updated. Change made. We suggest that the penalty for not investigating an operation timely should only qualify for a moderate VSL given immediate (within 1 hour or 1 day) activity is not required. We feel investigation of all operations and determination and implementation of correction misoperations is important to the long-term reliability of the BES. However, the system should be designed with redundancies to resolve any short-term issues and this Standard, while important, is designed to ensure long-term protection. Furthermore, we are not aware of any company who feels that the violation severity level determines whether they comply or not. Our organization strives to comply with all Standards with no violations, regardless of the violation severity level. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners’

Organization	Yes or No	Question 3 Comment
		responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Northeast Power Coordinating Council	No	We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.		
Northeast Utilities	No	We agree with the content of all the measures and VSLs, however measure M1 would have to be modified accordingly to coincide with the modifications suggested in question 2 above.
Response: The drafting team thanks you for your comment. The Measure(s) have been revised for clarity and to be more concise. Change made.		
ExxonMobil Research and Engineering	No	
SERC Protection and Controls Subcommittee	Yes	none
Tri-State G&T	Yes	The first instance of the abbreviation, DME, is undefined in M1 on page 7. It is defined as Disturbance Monitoring Equipment on page 19 in the Guidelines and Technical

Organization	Yes or No	Question 3 Comment
		Basis section for R1. The definition should be moved to page 7.
Response: The drafting team thanks you for your comment. The abbreviation "DME" is a NERC defined term and acronym in the NERC Glossary of Terms Used in NERC Reliability Standards. For clarity, the acronym has been spelled out. Change made.		
Exelon Corporation and it's affiliates	Yes	The following changes are suggested: R1 - Add a Lower VSL condition that states, "The responsible entitiy failed to identify and review at least 2% or 2 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Add a Moderate VSL condition that states, "The responsible entitiy failed to identify and review at leastr 3% or 3 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Add a High VSL condition that states, "The responsible entitiy failed to identify and review at least 4% or 4 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". Modify the 2nd Severe VSL condition with, "The responsible entitiy failed to identify and review at least 5% or 5 (whichever is greater) Protection System operations that operated one of its BES interrupting devices in accordance with Requirement R1, Part 1.1". **Response:** A weighting factor (i.e., use of percentages) is practical for assessing violations for fixed quantities, because Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made. Eliminate the 2nd Lower VSL condition all together because it is redundant with the 1st Severe VSL condition that addresses performing the actions in accordance with

Organization	Yes or No	Question 3 Comment
		Requirement R1, Parts 1.1 and 1.2 in more than 170 days. **Response:** The standard has been revised to provide one activity for a single reliability goal in accordance with standard drafting guidelines. The drafting team restructured the previous requirements into separate requirements which required the VSLs to be modified substantively. Change made. R2 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R3 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. R4 - Eliminate the last Severe VSL condition that is listed because it is redundant with the 1st Severe VSL condition listed. **Response:** The VSL parts are not redundant. One part addresses a completed action, but was late and the other an incomplete action. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Colorado Springs Utilities	Yes	
seattle city light	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
City of Tacoma, Tacoma Public Utilities	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Rayburn Country Electric Cooperative	Yes	
Georgia Transmission Corp	Yes	
Xcel Energy	Yes	
ITC Holdings	Yes	
Lincoln Electric System	Yes	
ReliabilityFirst	Yes	
Idaho Power Company	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Ingleside Cogeneration LP	Yes	
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery Company LLC	Yes	
Public Service Company of New Mexico	Yes	
City of Austin dba Austin Energy	Yes	

4. **The drafting team modified the Guidelines and Technical Basis section to provide more supporting discussions, explanations, and examples for the various aspects of the standard. Do you have any specific suggestions for further improvements?**

Summary Consideration:

The following resulted in a revision to the proposed standard. The most significant comment here was presented by at least four comments supported by 20 individuals concerning the use of "composite Protection System." The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the term "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System.

Approximately four comments from individuals were concerned about the use of reverse power relays. Because reverse power relays provide anti-motoring protection for generators, the drafting team has clarified in the Application Guidelines the relay's protective function intended use as a control function for shutting down a generating unit and as anti-motoring protection.

The remaining narrative responds to comments from two or fewer comments that are not addressed in other summaries:

- The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "…and requires the CAP implementation be less than 180 days."). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change.
- Requirement R4 now addresses the "action plan" as investigative action the entity performs when circumstances require additional study or time to determine the cause of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation.

Other single comments were too numerous and different to summarize here. Please see the comments below for these comments.

Organization	Yes or No	Question 4 Comment
ACES Standard Collaborators	No	(1) If the drafting team intends to move forward with "composite Protection System," we recommend adding it as a new proposed definition. After reading the technical guidelines, we are not persuaded that the drafting team has articulated the difference

Organization	Yes or No	Question 4 Comment
		between a Protection System and a composite Protection System. A proposed glossary term would allow industry the opportunity to provide the feedback as to whether an additional term is needed in order to have the proper scope for identifying Misoperations.
Response: The drafting team thanks you for your comment. The use of the term "composite" Protection System is intended to address the fact that the term Protection System by itself does not indicate that it is the complete set of protective relaying for an Element such as any primary, secondary, local backup, and communication-assisted relay systems. The word "composite" used as a modifier to Protection System was developed by the NERC SPCS to indicate the total complement of protection for a system Element (line, bus, transformer, generator, etc). To clarify the usage of the terminology, the drafting team is proposing a definition for "Composite Protection System" and has made corresponding changes where "composite Protection System" occurs in the body of the project documents. Change made.		
American Electric Power	No	AEP recommends adding "remote backup relaying is not considered to be part of the composite Protection System" to the end of the description for the composite Protection System in the Application Guidelines. **Response:** This recommendation has been incorporated into the proposed term "Composite Protection System." Change made. AEP requests that SDT include a clarification of the meaning of "BES interrupting device" within the context of this standard (similar to how "composite Protection System" is addressed). **Response:** The use of "BES interrupting device" has been clarified in the standard's Application Guidelines under the "Definitions" section. Change made. AEP recommends replacing both instances of the word "implementation" with "development" in the second paragraph of page 20 of the clean version of the standard. Otherwise it is implied that there are situations where a CAP must be fully implemented within 180 days. **Response:** The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "…and

Organization	Yes or No	Question 4 Comment
		requires the CAP implementation be less than 180 days.”). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made. Please include a clarification of the CAP and action plan modification tracking. For example, if a CAP or action plan is modified, is it sufficient to document the modifications, or must the date the modifications were made also be tracked? **Response:** The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made. The Measure M6 includes “dated” documentation to improve clarity. Also, examples were added to the Application Guidelines under Requirement R6. Change made. On page 15 of the clean version of the standard AEP recommends adding “unintentional” before “loss of field” in the first paragraph. **Response:** See Example 2a in the Application Guidelines under the Misoperation category 2 (Failure to Trip – Other Than Fault) discussion. Change made. On page 15 of the clean version of the standard AEP recommends replacing “shut down” in the second paragraph with “as intended to isolate.” **Response:** See Example 2b in the Application Guidelines under the Misoperation category 2 (Failure to Trip – Other Than Fault) discussion. Change made. AEP recommends adding generation examples of both a normal time delay operation and a misoperation to category 3 of the application guidelines. **Response:** Alternatively, the drafting team revised the definition of Misoperation category 3 (Slow Trip – During Fault) for clarity. Changed made.

Organization	Yes or No	Question 4 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Liberty Electric Power LLC	No	Agree with the comments of the Standards Development Team of the North American Generator Forum, which state: The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), "Primary motoring protection is provided by reverse power relays for all unit types." Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay's use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.		
Idaho Power Company	No	Only a request that the application guidelines be maintained with the final version of the standard.
Response: The drafting team thanks you for your comment. The Application Guidelines will remain part of the standard. Change made.		
Los Angeles Department of Water and Power	No	Please see answer to Question 5
Response: The drafting team thanks you for your comment; and refers to the response provided in Question 5.		
Dominion	No	The addition of the word "composite" adds nothing to the existing term Protection System and in fact introduces confusion. Dominion assumes a Missoperation occurs

Organization	Yes or No	Question 4 Comment
		only if all protection (primary, secondary, backup, pilot and non-pilot relay schemes) failed to operate as intended. If this assumption is incorrect, please clarify.
Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made.		
Texas Reliability Entity	No	The first paragraph of the Guidelines and Technical Basis defines the composite protection system to include the backup protection. This needs to be clearly defined as "local backup" only and not to include remote backup protection.
Response: The drafting team thanks you for your comments. The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made.		
Tennessee Valley Authority	No	The PRC-004-3 requirements' rationale for each requirement (gray boxes next to each requirement) and the Guidelines and Technical Basis (at the end of the document) are well thought out and contain significant justification and logic for each standard requirement. Recommend either keeping this information attached to the standard or formalizing it into a reference document that will will be easily accessible to the electric power industry. There was no indication in the draft standard as to the repository of this significant information.
Response: The drafting team thanks you for your comment. The rationale boxes will be moved to the Application Guidelines portion of the standard upon industry approval and remains with the standard. No change made.		
Madison Gas and Electric Company	No	Under R4 there is confusion when the words "complete" is used. It should be stated (here and in the requirement) that an entity can extend the 180 days to complete if they have supporting documentation, i.e., parts on order, work orders, etc.

Organization	Yes or No	Question 4 Comment
Response: The drafting team thanks you for your comment. The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "…and requires the CAP implementation be less than 180 days."). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.		
Colorado Springs Utilities	No	
Northeast Power Coordinating Council	No	
Southwest Power Pool Reliability Standards Development Team	No	
City of Tacoma, Tacoma Public Utilities	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Arizona Public Service Company	No	
Operational Compliance	No	
Georgia Transmission Corp	No	
Xcel Energy	No	

Organization	Yes or No	Question 4 Comment
Public Service Enterprise Group	No	
Manitoba Hydro	No	
Tri-State G&T	No	
Wisconsin Electric Power Company	No	
Sacramento Municipal Utility District	No	
ReliabilityFirst	No	
City of Tallahassee	No	
Northeast Utilities	No	
Entergy Services, Inc. (Transmission)	No	
Ingleside Cogeneration LP	No	
ExxonMobil Research and Engineering	No	
City of Tallahassee	No	
City of Tallahassee - Electric Utility	No	

Organization	Yes or No	Question 4 Comment
Hydro-Québec Procution	No	
Public Service Company of New Mexico	No	
ITC Holdings	Yes	We have no issues with the guidelines, provided there is clarification that the guidelines are not to be used to support audit data request or findings.
Response: The drafting team thanks you for your comment. The Measures are used to support performance with the Requirements. The Application Guidelines are not enforceable. No change made.		
SERC Protection and Controls Subcommittee	Yes	1) Unknown / unexplainable is the 'cause' of about 12% of Misoperations per NERC reports. An R3 'no further action' declaration example would be helpful. Perhaps your 'no action plan' declaration example on page 23 was intended for this. If so, please so state there. **Response:** In the Application Guidelines, see the last paragraph of the section Requirement R5 (previously R3) which notes a declaration that no further corrective actions will be taken is expected to be used sparingly. No change made. 2) Please replace 'reverse power' with 'overexcitation' on page 15 in the failure to operate for a non-fault condition section. Reverse power relays are usually excluded so the example is confusing as is. **Response:** The Application Guidelines (Failure to Trip – Other Than Fault) have been clarified. Example 2b replaced "reverse power" with "over excitation." Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
City of Austin dba Austin Energy	Yes	Austin Energy (AE) recommends the following changes in the Guidelines and Technical Basis section: (1) Remove the reference of reverse power relaying from item #2. This reference can

Organization	Yes or No	Question 4 Comment
		be confusing because the protection scheme is used for safe shutdown of a generating unit. A substitute example would be "A failure of a "primary" loss of field relay is not a failure to trip Misoperation as long as another component of the generator's composite Protection System opertated to shut down the generator." **Response:** The Application Guidelines (Failure to Trip – Other Than Fault) have been clarified. Example 2b replaced "reverse power" with "over excitation." Change made. (2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. AE believes this would clarify what relay systems are excluded before reading the parts of the definition and requirements. **Response:** The Application Guidelines have been revised for clarity by grouping topics. See the heading "Special Cases." Change made. (3) The second paragraph on page 26 of the redline, which reads "With the ultimate goal of keeping the implementation time of a CAP as short as possible, if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days" is not consistent with the Standard Requirements and should be removed. The standard requires CAP development within 180 days, not CAP implementation or completion in 180 days. **Response:** The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "…and requires the CAP implementation be less than 180 days."). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Exelon Corporation and it's	Yes	Exelon would like additional clarification added to the Application Guide regarding the inclusion of CAP corrective actions for addressing the application of the CAP to other

Organization	Yes or No	Question 4 Comment
affiliates		Protection Systems owned by the utility. Specifically, the Guide should address that such a CAP can be considered complete once a program (required to address application of the CAP to other Protection Systems) is developed. Example 2 in the Application Guide exemplifies this notion. Additionally, application of the CAP to other Protection Systems owned by the utility should be considered fulfilled if an existing program (such as Protection System maintenance and testing practices) fulfill the actions necessary to address such a CAP.
Response: The drafting team thanks you for your comment. Examples have been provided in the Application Guidelines to illustrate the evaluation of the entity's other Protection Systems including other locations within the CAP. The CAP is not complete until all actions in the CAP are satisfied. An entity may create an action within a CAP in which it states that a program outside the CAP will be used to address similar issues at other locations. In this case the CAP is not declared complete until the program is developed. See Example R6b in the Application Guidelines. Change made.		
Pepco Holdings Inc & Affiliates	Yes	On page 18 of the Guidelines and Technical Basis section it states "Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The drafting team believes the owner of the BES interrupting device that operated would be in the best position to analyze the Protection System Operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation." Furthermore, on page 19 it states "Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation ..."Based on the arguments presented in our response to Question 2 we vigorously disagree with this assertion. When a Protective System operates, a means is provided to determine which protective component initiated the trip (i.e., relay targets, lockout relay operations, microprocessor relay event logs, etc.) The owners of these Protective System devices, which initiated the trip of the interruption device, are much better suited to investigate the cause of the Protective System operation than the owners of the interrupting device. In addition, all previously approved versions of PRC-004 rightly place the responsibility for reviewing and analyzing Protective System operations on the owners

Organization	Yes or No	Question 4 Comment
		of the Protective Systems, not the owners of the interrupting device. The interrupting device is, by definition, not even a component of a Protective System. We agree that if the owner of the relay that initiated the trip does not own all the remaining components of the associated Protection System (i.e., CTs or VT's) they may require assistance and support from the owners of those additional components to complete their analysis. However, the owner of the Protective System that initiated the trip should be the party responsible for analyzing if a protective system misoperation occurred. If in the course of that investigation they determine the cause was attributed to a component of the Protection System which they did not own (such as a blown VT fuse owned by others), they should notify the other party, who would in turn be responsible for appropriate corrective action. In conclusion, nowhere in this standard should compliance responsibility be assigned to the owner of an interrupting device.
Response: The drafting team thanks you for your comment. According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. Requirement R1 was revised to bring clarity to the obligations of each applicable entity. Change made.		
Rayburn Country Electric Cooperative	Yes	Prefer the term "entire" to "composite" again for clarity sake since entire seems more intuitive in nature rather than composite which requires some anylitical thought to apply it. Example, a transformers entire protection system is slow to operate. Versus, a transformers composite protection system is slow to operate.
Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term "Composite Protection System." Change made.		
Duke Energy	Yes	See our comment above on Question #1. The following paragraph should be deleted

Organization	Yes or No	Question 4 Comment
		from the accompanying Guidelines and Technical Basis section: “The reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements in the TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.”
Response: The drafting team thanks you for your comments. The reference to the TPL standards in both the Misoperation definition and body of the standard has been removed. Change made.		
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Southern Company supports the SERC comments and are including the following additional comments: 1. In various locations of the text, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misopeartion rather than simply that they are not misoperations (we believe that they are still misoperations). We believe that entities should be allowed to determine whether or not the Protection System operated appropriately. This is inherent in our suggested simpler definition of Misoperation through including "than intended". **Response:** The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition “Composite Protection System” which has an exclusion for backup protection provided by a remote Protection System. Change made. 2. In the text for section 6 of the Misoperation definition, we disagree with the phrase "An operation that occurs during a non-fault condition but was initiated by on-site maintenance, testing, inspetion, construction or commissioning is not a Misoperation." This is obviously an unnecessary trip - other than fault. This should be included in a list of non-reportable misoperations.

Organization	Yes or No	Question 4 Comment
		Response: The on-site maintenance exception in the Misoperation definition, Unnecessary Trip – Other Than Fault (category 6) was added during the draft 2 development of the standard based on industry comment. An operation due to on-site maintenance would not be a Misoperation; therefore, not reportable. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Nebraska Public Power District	Yes	The drafting team should review the BES Definition drafting team documents and evaluated how it relates to misoperations. It would be desirable to avoid any disconnects or conflicts between these definitions and standards. Some BES Definition drafting team documents indicate individual wind turbine generators are part of the BES. Is misoperation data desired down to this level? During Webinars explaining the BES definition documentation questions were asked regarding how the BES documentation helps identify or determine what protection systems are included for PRC-005. The BES drafting team stated that protections systems for PRC-005 are not to be defined by the equipment identified in the BES definitions documentation but instead are to be defined the PRC-005 standard and documentation. Would this be the case for PRC-004-3 as well?
Response: The drafting team thanks you for your comment. This standard applies to Protection Systems for BES Elements in achieving its goal to identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements. Entities will apply the BES definition to determine applicability to its Protection Systems. No change made.		
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	Yes	The NSRF appreciates the addition of the Application Guide at the end of the Standard. The Application Guide will help NERC, the Regional Entities and Registered Entities to move away from a zero defact CMEP process.
Response: The drafting team thanks you for your comment.		
PPL NERC Registered Entities	Yes	The standard should completely exclude operation of reverse power relays when

Organization	Yes or No	Question 4 Comment
		shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), "Primary motoring protection is provided by reverse power relays for all unit types." Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay's use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.		
Essential Power, LLC	Yes	The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the distinction attempted between control and protection functions of reverse power relays is obscure.
Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), "Primary motoring protection is provided by reverse power relays for all unit types." Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay's use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.		
Cogentrix Energy Power Management, LLC	Yes	The standard should completely exclude operation of reverse power relays when shutting-down units, or (better) classify such devices as not being part of Protection Systems (they do not protect BES equipment; they prevent turbine mechanical damage). This subject is discussed in the Application Guidelines (p.17), but the

Organization	Yes or No	Question 4 Comment
		distinction attempted between control and protection functions of reverse power relays is obscure.
Response: The drafting team thanks you for your comment. According to the IEEE Guide for AC Generator Protection (C37.102-2006), Section 4.5.5 (Motoring), sub-section 4.5.5.6 (Tripping mode), "Primary motoring protection is provided by reverse power relays for all unit types." Reverse power relays, by definition, are a Protection System and cannot be categorically excluded. Because reverse power relays provide motoring protection, the drafting team has provided an exclusion in the Applicability of the standard. Also, this exclusion is clarified in the Application Guidelines concerning the relay's use as a control function for shutting down a unit and as anti-motoring protective protection for a generating unit. Change made.		
Kansas City Power & Light	Yes	There are some examples of CAP in the document. Adding examples relative to my comment in question 5 would be beneficial.
Response: The drafting team thanks you for your comments. The comment in Question 5 ("Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability…") contains an example and discussion that was previously addressed in the Application Guidelines under Requirement R2 in the last paragraphs. No change made.		
Luminant Power	Yes	Luminant recommends the following changes in the Guideleins and Technical Basis section. 1) Remove the reference of reverse power relaying from item #2. This reference can be confusing since the protection scheme is used for safe shutdown of a generating unit. An substitute example would be "A failure of a "primary" loss of field relay is not a failure to trip Misoperation as long as another component of the generator's composite Protection System opertated to shut down the generator." **Response:** Change made. 2) References to generator Protection Systems that are exempt should be removed and placed in the opening section similar to the exclusions used to exempt circuit breaker and other interrupting device mechanisms. Luminant believes that this would clarify what relay systems are excluded before reading the parts of the definition and

Organization	Yes or No	Question 4 Comment
		requirements. **Response:** A section called "Special Cases" has been added to the Application Guidelines. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Mary Jo Cooper	Yes	
ISO RTO Council Standards Review Committee	Yes	
seattle city light	Yes	
American Transmission Company, LLC	Yes	
Ameren	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

Summary Consideration:

The following resulted in a revision to the proposed standard. Many of the comments here were also summarized above. These are the most significant comment themes that resulted in a change to the proposed standard. They are summarized here and may be duplicative of other summaries:

At least another five comments supported by about 17 individuals raised questions concerning the action plan of investigative actions. Requirement R1 now includes identification of Misoperation and determination of a cause. If a cause is not readily apparent, further investigative actions may be undertaken (Requirement R4) until a cause is determined or a declaration of no cause can be determined. The concept of an action plan has been eliminated from the standard.

About five comments supported by ten stakeholders requested clarity concerning time periods or Protection System owner's responsibilities. The result was that the drafting team revised Requirement R1 to provide clarity on each Protection System owners' responsibilities following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components, time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation.

Approximately two comments represented by 17 individuals raised questions concerning the data request. The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end.

At least two comments supported by about 13 individuals asked for clarification on the use of "BES interrupting device." The drafting team has clarified the use in the standard's Application Guidelines under the "Definitions" section.

The following did not result in a change to the proposed standard. This next summary lists the most significant themes of these comments that did not result in a change to the proposed standard. They are summarized here and may be duplicative of other summaries:

Approximately seven comments supported by 26 stakeholders addressed the topic of internal controls. The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authority (CEA) to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related

Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process.

About three comments representing at least 22 individuals mentioned having a Reliability Standard Audit Worksheet (RSAW). The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3.

At least four comments supported by 13 stakeholders requested clarity about the Corrective Action Plan (CAP). The drafting team noted that the NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP.

About four comments supported by at least ten individuals suggested alternatives to make the standard less burdensome using metrics. One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance.

Two comments were concerned about the slow trip category of the Misoperation definition as it pertains to having the ability to measure a slow operation. This includes having Disturbance Monitoring Equipment (DME) and the compliance approach.

The remaining comments were individual in nature; please see the individual comments for detail.

Organization	Question 5 Comment
City of Austin dba Austin Energy	(1) For events where a BES breaker operates but the Registered Entity does not own all of the Protection Systems, it is possible the other owner would not be notified until 120 days has elapsed. This is counter the the expectation of the drafting team that “it is expected that both entities will work together to investigate the cause of the operation.” Austin Energy (AE) recommends re-writing the bullets of R1 to require notification within a set number of days (AE recommends 15 calendar days) and then require the entities to work together as necessary. AE provides language revisions for

Organization	Question 5 Comment
	consideration: R1.1. Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation. --If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation. --If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, notify the other owner(s) of the Protection System component(s) within 15 calendar days. --The BES interrupting device and Protection System component owner(s) notified by the BES interrupting device owner shall work together to determine if there was a correct operation or a Misoperation of their component. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. (2) By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an Action Plan in the standard. They may appear to be the same. AE believes the intent of the action plan is to document an investigation plan, so recommends that additional language be added to the Rationale box for R2 that describes the intent of a CAP (as Corrective Action to avoid future recurrance) and an action plan as an investigation or other non-Corrective plan of action to investigate the cause of a misoperation or to determine if a misoperation has occured.

Organization	Question 5 Comment
	Response: Action plan has been removed from the Standard and replaced with investigative actions in R4. CAP development is covered by Requirement R5 and CAP implementation by Requirement R6. Change made. (3) AE appreciates the efforts of the Standard Drafting Team and supports the goal of keeping the misoperation identification and correction processes as short as possible. There can be cases where extra time is necessary and the entire process may take longer than 180 days. The Standard allows for these extreme cases as written, assuming an action plan allows for the additional investigation of an operation or misoperation. For instance, if the cause of a misoperation cannot be identified, the entity may create an action plan to further research/analyze the cause (possibly the entity must ship equipment back to the OEM for cause determination). Once the cause is identified, then the Corrective Action Plan must be developed within 60 days. AE recognizes, and agrees with the Standard Drafting Team's intent to ensure active analysis and appropriate corrective actions are adequately considered and/or implemented. Although it is likely there is sufficient time to analyze operations, identify misoperations and take corrective action for most events within the standard as written, there is a significant administrative burden involved to demonstrate action plans and/or corrective action plans are developed within the proper timelines. Therefore, although AE believes the timelines are workable as written, AE provides the following alternative recommendation. Remove all of the required timelines and instead require the investigation/action plans and Corrective Action Plans only. These action plans and Corrective Action Plans contain timelines that must be followed by their very nature. **Response:** The timelines within the standard provide the entity a period of time from the BES interrupting device operation to identify any potential Misoperation and its cause. For cases where an entity needs to perform additional investigation beyond 120 calendar days, the drafting team added a proposed Requirement R4 which provides the entity a mechanism to continue investigative actions by documenting its progress within established periods. The owner of the Protection System components that Misoperated has the ability to establish its own timetables within each CAP. The

Organization	Question 5 Comment
	requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation identification, determining the cause, and the development and implementation of the CAP. The associated dates and timetables allow the Requirements to be measurable. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Ameren	(1) Please clarify the sentence on page 17, the second to last paragraph, "Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations" by putting it in a new paragraph and including some examples. Does the protected Element have to be out of service? Is this intended to include human error (e.g. bumping the panel) caused trips by personnel other than Protection System maintenance personnel? **Response:** It is important to emphasize that the maintenance exclusion is for active maintenance. A remote-end trip is included in the existing exclusion if it resulted from “on-site” activities at a different location. The Application Guidelines have also been enhanced with an example (6d) related to this topic. Change made. An example of an “Element out of service” would be a breaker that is switched out of service with the breaker disconnects open. If the breaker failure scheme operates due to a problem with the scheme, several in-service Elements could be tripped. No change made. (2) Please add "completed" on page 20, near the bottom, so that the title reads " The following are examples of completed Corrective Action Plans (CAPs):" **Response:** The word “completed” was incorporated into the text discussing the completed CAPs. See the examples under Requirement R6 in the Application Guidelines. Change made. (3) In addition to our comments, we also agree with the SERC Protection & Control

Organization	Question 5 Comment
	Subcommittee (PCS) comments and include them by reference. **Response:** Please see the response to the SERC Protection & Control Subcommittee (PCS).
Response: The drafting team thanks you for your comments; please see the above responses.	
ACES Standard Collaborators	(1) We recommend introducing the term "BES interrupting device" as a new definition with clearly defined parameters. **Response:** The use of "BES interrupting device" has been clarified in the standard's Application Guidelines under the "Definitions" section. Change made. (2) We would like more information on the Section 1600 data request for Misoperation data. Also, if a data request is going to be utilized, will registered entities still need to continue reporting under PRC-004-2? This would be a redundant process and we encourage NERC to coordinate the timing of the data request to take the place of the current reporting requirements. **Response:** The NERC Rules of Procedure, Section 1600 Request for Information or Data (i.e., Data Request) will dictate the specific entity (i.e., Protection System component owner) that is to report a Misoperation and the format for reporting. Reporting under the standard will end. No change made. Further, we disagree with the evidence retention section of this standard. TO, GO, and DP are audited on a six-year cycle, which is too long of a timeframe to retain evidence. We suggest shortening the amount of time to three years, unless there is an open or ongoing investigation, action plan, or CAP. If there is a section 1600 data request, why does the data need to be retained? NERC already has the information. **Response:** The Evidence Retention section has been revised using the Drafting Team Guidelines guidance for evidence retention that was endorsed by the Standards Committee, April 2009. All requirements have been reduced to 12 calendar months as the minimum retention period according to standard drafting guidelines. Change made.

Organization	Question 5 Comment
	The drafting team removed the reporting obligations from the standard and is working with NERC staff to develop a data request under Section 1600 of the NERC Rules of Procedure. The drafting team notes that the standard and data request have been developed in a manner such that evidence used for compliance of the standard and data request are intended to be independent of each other. The 1600 data request does not eliminate the need to retain PRC-004 data. The data request will be submitted for approval at the time the revised standard is submitted. Data retention is included as part of the standard because it is essential for auditing compliance with the standard. No change made. (3) This standard is another candidate for implementing internal controls, and should not contain “zero-defect” language. For example, an entity should be able to have controls in place to determine whether Misoperations are being identified, assessed and corrected. This is the essence of PRC-004-3, and therefore should be revised to include these concepts. There should not be zero-defect penalties if an entity has controls to catch errors and fix them. Currently, the standard would penalize an entity for each instance of noncompliance. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. (4) We continue to be confused by the interaction of Requirements R1 and R3. While R1 does not compel the protective relay owner to identify the cause of a Misoperation, it does compel the owner to investigate the Misoperation. One would presume an auditor would expect investigative actions conducted for Requirement R1 to be

Organization	Question 5 Comment
	reasonable. However the application guidelines section for Requirement R3 states clearly on page 14 that this requirement only applies if "reasonable investigative actions have not been exhausted". Thus, it would appear that Requirement R3 could never apply without a violation of Requirement R1 Part 1.2. We think the interaction of these requirements need further clarification. Furthermore, we suggest that Requirement R3 could actually be made part of Requirement R1 which would help alleviate the confusion. For example, Part 1.2 could have a subpart that states that an action plan should be developed for any reasonable investigative actions that may require more than 120 days to complete. Another part could be to document why the cause cannot be identified. **Response:** This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made. (5) Since UVLS is specifically excluded in the applicability section does it make sense to include it under voltage conditions in part 2 and 4 of the Misoperation definition? **Response:** There are other Protection Systems that trip for undervoltage conditions besides UVLS. No change made. (6) Why can't the implementation requirement R4 be included as a Part of the other requirements? Furthermore, it is questionable if it is even needed for FERC has stated in past orders that there is an implied obligation to implement plans, policies and procedures when a requirement compels their development. This requirement is similar to the types of standards that would be subject to Paragraph 81. **Response:** Placing the implementation in a separate requirement makes it more visible and makes it a separate compliance element. No change made. (7) Thank you for the opportunity to comment.

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	Response: Thank you for your comments.
Response: The drafting team thanks you for your comments; please see the above responses.	
Madison Gas and Electric Company	: (1) As written in R1.1, if a BES generator's normal shut down cycle is caused by a Protection System operation (a set trip point in the relay) then each shut down would be required to be "identified and reviewed". This is similar to issues that a generator operator has under Project 2011-INT-02 AVR control during start up and shut down. MGE recommends that either a footnote be provided to address the exclusion of normal shut down processes or add another bullet excluding a generators normal shut down processes where the unit's breaker is activated via a set point within the Protection System (i.e., relay). **Response:** The drafting team has provided additional detail concerning the use of protection and control functions for generators in the Application Guidelines regarding reverse power relays. The proposed standard's Applicability excludes certain intended uses of protection functions as control functions. Change made. (2) R4 could be viewed as allowing for CAPs to be extended beyond 180 days (the maximum days in the combonation of R1 and R2). If this is the intent of the SDT, then clearly state this within the requirement. As written, an entity could be in violation of the maximum time frame of 180 days by extending the CAP under R4. **Response:** The Application Guidelines have been clarified not to infer the implementation of the CAP must be completed in 180 days (See draft 3, page 20 "…and requires the CAP implementation be less than 180 days."). The CAP has its own timetable which is required to be updated by the entity when actions or timetables change. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Dominion	: (1) Suggest the Implementation Plan be modified under the Applicaibility section as

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	indicated below: This standard applies to the following Facilities: Protection Systems for BES Elements. Underfrequency Load Shedding (UFLS) that trips a BES Element This standard does not apply to the following Facilities: The flowing Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) Non-protective functions that may be imbedded within a Protection System **Response:** The exclusion language concerning SPS and RAS in the previous posting has been removed from the Applicability and added to the rationale. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this version of the standard because they will be handled in the second phase of this project. UVLS is covered by PRC-022-1 under Project 2008-02 – Undervoltage Load Shedding. Change made. (2)Suggest the Mapping Document be modified under the Proposed Language in PRC-004-3 column as indicated below: 4.2.1 Protection Systems for BES Facilities, Facilities needs to be replaced with Elements. **Response:** The mapping document has been corrected to be consistent with the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
SERC Protection and Controls Subcommittee	(1) Some entities presently use their PRC-004 reporting as a means of documenting CAPs. They may prefer to use your proposed data request under Section 1600 of the NERC Rules of Procedure for these purposes. Please change page 5 wording to “The data submitted as part of the data request will not be used by NERC or the Regions for compliance or enforcement purposes.” **Response:** The sentence, “The data submitted as part of the data request will not be used for compliance or enforcement purposes” has been removed because the drafting

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	team does not have this authority. The drafting team notes that the standard and data request have been developed in a manner such that evidence used for compliance of the standard and data request are intended to be independent of each other. Change made. (2) Compliance section 1.2 on page 9 states "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall keep data or evidence to show compliance with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation." Please delete "and Measures M1, M2, M3, and M4" because entities must comply with Requirements, but Measures are not allowed to expand that scope. **Response:** The reference to each Measure under Section 1.2 – Evidence Retention is consistent with the standard drafting guidelines. No change made. (3) In the first sentence of R2 on page 7, please add "first" before "cause" so it reads "Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the first cause of each Misoperation: ..." Pages 19 and 20 make it clear that this is triggered by the first cause, but some entities may miss this application guidance. **Response:** The word "first" has been included. Change made. (4) Please include 'Composite Protection System' as a defined term that remains with this standard (similar to PRC-005-2 approach for Component, Component Type, etc.). Your definition on page 14 is fine, but move it up to just after the page 3 Definitions. Regarding commments for all questions 1-5 above: **Response:** The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made.

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	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.
Response: The drafting team thanks you for your comments; please see the above responses.	
Seminole Electric	1. The Proposed PRC-004-3 combines PRC-004-2a and PRC-003-1. This project is applicable to a "Distribution Provider" whereas PRC-004-2a is applicable to a "Distribution Provider that owns a transmission Protection System." Does the STD believe that the additional caveat should be added to the Distribution Provider (DP) applicability, i.e., that the DP need to own a transmission Protection System? **Response:** Applicability 4.2.1 specifies that PRC-004-3 is applicable to Protection Systems for BES Elements; therefore, the reference is not necessary. No change made. 2. In the "Purpose/Industry Need" section that the STD developed for this Project, the STD states that because PRC-003-1 was never approved by the Commission, "there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2... This could lead to a potential reliability gap." (Emphasis added). This infers that there is a need for some form of standardized regional mitigation requirements. When NERC drafted PRC-003-1, NERC made RROs the applicable entity in order for each RRO to "establish, document and maintain is procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations." (See R1. of PRC-003-1). However, in the proposed action, PRC-004-3 does not appear to require any such regional processes for misoperations mitigation. In fact, the new proposed Standard is not even applicable to RRO as the new standard does not require the RRO to perform any action. It does not appear that the new draft Standard mitigates the deficiency left by the non-approval of PRC-003-1 and so this should be addressed via the addition of some form of regional analysis requirement. **Response:** This standard or any NERC Reliability Standard cannot place any requirements on the Regional Entity. The proposed PRC-004-3 standard addresses

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	mitigation through the development of the CAP to correct the cause(s) of Misoperations. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
ReliabilityFirst	Although this draft of the standard is considered a Results-Based Standard it is difficult to see how the requirements are written to achieve a measurable outcome associated with reaching a level of reliability performance, a reduction in reliability risk or a necessary level of competency. This draft standard instead appears to be administrative in nature that is more concerned with creating documentation solely for compliance purposes. The following are specific issues or suggestions: 1) the standard contains extra 120 day and 60 day deadlines that do not provide reliability benefit. Although there is value in investigating Misoperations quickly, it is more important to fix the problem and prevent its reoccurrence. **Response:** Identifying Protection System Misoperations then determining and rectifying their causes will improve reliability. The time frames stated within the standard are maximum times, not minimum. An entity should resolve Misoperations as quickly as possible. However, due to the possibility of seasonal peaks in operations it was deemed necessary to provide for ample time to review large numbers of operations and schedule the outages sometimes necessary for investigations. No change made. 2) Late identification of Misoperations will be a violation even if they are not particularly significant. Specifically, Misoperations that occur with no Fault present may not be readily apparent. The deadlines in the standard could cause disincentives to fully investigate Protection System performance because it may result in compliance violations. **Response:** Prompt identification of a Misoperation is important regardless of its perceived significance. Identifying a Misoperation and its cause(s) leads to preventing reoccurrence which, without correction, could lead to a reduction in reliability. Additionally, the identification of a Misoperation cause leads the entity to considering

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	its other Protection Systems including other locations which may result in identifying and correcting a potential problem with another Protection System which may be significant to reliability. The standard provides options for entities to explain why actions were not taken. No change made. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. 3) The standard provides no means of ensuring that Misoperations are addressed by CAPs on a timely basis. Of particular concern is failure to trip (- during Fault) type Misoperations. The cause for this type of Misoperation should be either mitigated or the CAP completed in less 12 months. **Response:** The scope of a CAP can vary greatly depending on whether the entity chooses to implement a CAP to correct a single cause or multiple causes (e.g., including other locations); therefore, the risk prioritization and timetable to complete the CAP is at the discretion of the entity. No change made. 4) It is suggested that the drafting team embrace a reliability performance based approach that would fit into the results-based philosophy. Specifically, adherence to the standard should be based on achieving or surpassing certain metrics such as Misoperation rate, the percent of causes unidentified (Unknowns/All in a year) and the percentage of open CAPs (Open CAPS/Misoperations in a year). These metrics are meant only as potential examples for measuring performance. By requiring certain levels of performance or continuous improvement in these metrics, then the goal of the standard can be met without the administrative burden of tracking relatively unimportant dates such as when a cause was identified or when a CAP was developed

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	and the storage of large volumes of evidence records. **Response:** One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Colorado Springs Utilities	As noted in the response regarding R1. We believe that the specific terms need to be clarified in R3 as well to clarify the intended scope of covered situations.
Response: The drafting team thanks you for your comments. The occurrences of “BES Protection System” have been revised to pertain to “Protection Systems for BES Elements.” The use of “BES interrupting device” has been clarified in the standard’s Application Guidelines. Change made.	
Manitoba Hydro	Background - The words 'by requiring applicable entities to' would make sense after the words "The proposed requirements of the revised Reliability Standard PRC-004-3 meets the following objectives". Moreover, the terms Special Protection Systems, Remedial Action Schemes and Under-Voltage Load Shedding are used at the end of the Background section when these terms have already had acronyms attached to them above. **Response:** The suggested change does not provide any additional clarity. No change made. R2 - the words 'If a cause is identified' after the words 'cause(s) of each Misoperation' would be helpful. The way It reads, R2 is only applicable if a cause is identified and R3 is applicable if a cause if not identified so the Measures for each should be drafted in a

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	way that makes that point clear. **Response:** This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made. R3 - the words 'caused by a Protection System operation' should be added after BES interrupting device operation to make the wording consistent with the other requirements. **Response:** The phrase "caused by a Protection System operation " is only used in Requirement R1 when determining if a Protection System Misoperation has occurred. Once a Protection System Misoperation has been identified, an associated Protection System does not need to be restated in the requirements. The concept of an action plan (previously R3) has been eliminated from the standard. Change made. R4 - In reading the rationale for R4, it states that if a cause of a Misoperation is determined when implementing the action plan, you go back to R2 and develop a CAP. This isn't evident on the face on the wording of the standard and the Rationale will be deleted going forward. R4/M4 - should be consistent with use of 'and' or 'or' when referring to the CAP and action plan, perhaps best option is to use 'and/or'. **Response:** The rationale boxes will be moved to the Application Guidelines portion of the standard upon industry approval and remains with the standard. No change made. The concept of an action plan has been eliminated from the standard. Change made. Compliance - 1.1 - Manitoba Hydro has never before seen a reference to the definition of CEA per the NERC Rules of Procedure in this section, it seems unnecessary. **Response:** This is standardized text established by NERC for a Reliability Standard. No change made. Compliance - the phrase BES Protection System is elsewhere referred to as Protection

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	System for Facilities that are part of the BES which seems more accurate and should be consistently used. **Response:** The drafting team revised all the associated documents to reflect "Protection Systems for BES Elements." Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Oncor Electric Delivery Company LLC	By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms, it is unclear what differences exist between a CAP and an "action plan" as written in PRC-004-3. Both appear to be the same until the Rationale for R3 states "implementing an action plan of additional investigation/monitoring may determine cause and lead to the development of a CAP in accordance to Requirement R2." Oncor recommends that additional language be added that describes the intent and difference between a CAP and an "action plan". **Response:** The concept of an action plan has been eliminated from the standard. Change made. Oncor would also like clarification as to what authority the CEA holds in determining the effectiveness of the corrective actions detailed in the CAP and/or "action plan". **Response:** The CEA may determine if there is sufficient evidence that the entity has implemented their CAPs according to the criteria in each requirement. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
City of Tacoma, Tacoma Public Utilities	Comments: Is it the intention of the PSM SDT that this version of the standard would require that all BES interrupting device operations be logged (documented) with a determination of whether the operation was caused by a Protection System? While it appears to be the intent of the draft revised standard that all interrupting device operations be reviewed at some level to determine if a Protection System caused the

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	operation, it is unclear whether explicit documentation of each interrupting device operation must be generated and retained for purposes of compliance with PRC-004-3.
Response: The drafting team thanks you for your comment and intends that logging of the review occurs for those BES interrupting device operations caused by a Protection System operation or by manual intervention in response to a Protection System operation failure that meet the criteria in R1. The BES interrupting device owner would have evidence of its equipment operations and whether it was a Misoperation or not. The notified Protection System owner will use its notification to establish evidence of an operation. Routine switching operations are not intended to be logged and retained as evidence of compliance with this standard. No change made.	
Florida Municipal Power Agency	First, R4 uses the phrase “as needed.” In doing research for legal precedence interpreting the phase “as needed,” both in terms of contract interpretation and statutory construction, numerous cases throughout the country make it clear that, unless this phrase is clearly defined in the context in which it is used, this phrase is ambiguous and will only lead to conflict. For instance, the phrase indicates that (1) there is a level of discretion involved regarding an action that must be taken, and (2) someone must make a determination as to when such action is deemed “needed.” However, the standard is silent both as to what factors trigger the exercise of discretion and who makes the determination that a change to the CAP is “needed” - the entity or compliance staff. In this regard, FMPA recommends making it crystal clear what “as needed” means. For example, it could state “as needed to reflect any CAP revisions made by the responsible entity, as determined at the sole discretion of the responsible entity.” **Response:** The drafting team has revised Requirement R6 (previously R4) to removed “as needed” and added specificity that the CAP is updated when actions or the timetable changes. Change made. Second, R4 should recognize that not every investigation of a Misoperation ends in a CAP, e.g., those where no cause was found in accordance with R3. **Response:** This has been clarified by the new Requirement R1 (and R3) that requires the identification of Misoperation which is typically when the entity will determine the

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	cause. If a cause is not identified, further investigative actions must be taken (see new Requirement R4) until a cause is determined or a declaration of no cause is made. The concept of an action plan has been eliminated from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Midwest Reliability Organization NERC Standards Review Forum (NSRF)	For R2, depending on time of year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs for some entities. **Response:** The 60-day period is to develop the CAP and not necessarily to obtain funding. Part of the CAP itself can be time to obtain the funding necessary to complete the CAP. No change made. Also, the first bullet under R2 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies. **Response:** It is the responsibility of the Protection System owner to determine how wide spread the situation is and include the appropriate actions in its CAP. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations is intended to encourage diligence to prevent future Misoperations of the same cause and having an adverse effect on reliability. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Independent Electricity System Operator	Generally speaking, the standard is difficult to read, focusing on how instead of what. The drafting team should strengthen the description of the outcomes, and try to reduce the reliance on the application guideline and the rationales. (One has to read the rationales before understanding the meaning of the requirements.)
Response: The drafting team thanks you for your comment. Standards must focus on "what" is the required performance and not the	

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"how" to achieve the required performance. The standard may appear written as the "how," because requirements are based on the natural progression of the required performance. Several changes were made to the Requirements to improve clarity. Change made.	
Flathead Electric Cooperative, Inc.	Generally, the standard does not seem to address the reporint of no events now being required by the RE, especially for entities that have only a few devices, the reporting burden for non-events shoudl be clearly eliminated. It is not clear that it is eliminated. Only the reporting of actual misoperations should be required as defined.
Response: The drafting team thanks you for your comment. The reporting requirement has been removed from the standard. Change made.	
American Electric Power	In the Rationale for R2 box, a reference is made to R4. This appears to be a typo and should be changed to R3. **Response:** The requirements have been restructured causing the rationale boxes to change. Change made. Since an evaluation is not part of the Corrective Action Plan definition, please make the following modification to the first bullet of R2: " Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and also an evaluation of the Action Items applicability to the entity's Protection Systems at other locations, or.." **Response:** The drafting team agrees an "evaluation" is separate from the CAP and has modified the proposed Requirement R5 (previously R2). Change made. AEP recommends revising R2, R3, and R4 to specify that only the owner(s) of the Protection System component(s) that misoperated are responsible for applicable requirements. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. According to the standard, each entity has an independent responsibility to identify a Misoperation of its Protection System components, if any,

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	beginning with the BES interrupting device owner through any notified Protection System owner. Change made. Measure 2 should be revised to remove the statement “explaining why there is no need to develop a CAP.” This is consistent with Measure 3. **Response:** Measure M2 was revised and is now M5. Change made. Declaration is described elsewhere in the standard. The Standard may read more clearly if the existing R2 and R3 were switched such that the requirement to develop a CAP (R2) came *after* the requirement to identify a cause or develop an action plan (R3) to complete further investigation. **Response:** The Requirements were rewritten to clarify the two instances where a declaration can be used, one to end the entity’s investigation for a the cause of a Misoperation and the other to state why corrective actions (i.e., CAP) are beyond the entity’s control or would not improve BES reliability and that no further corrective actions will be taken. No change made. The phrase "composite Protection System", which is described in the Application Guidelines section, is not used in the Requirements, Measures, or Compliance sections. AEP requests "Protection System" to be replaced with "composite Protection System" where appropriate throughout the standard. **Response:** The drafting team is proposing a definition for the term “Composite Protection System.” Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Ingleside Cogeneration LP	Ingleside Cogeneration shares the project team’s desire to retain a scholarly and cooperative approach to the assessment of Misoperations. However, we believe that the regulatory pressure will mount - particularly as NERC’s events analysis numbers continue to show Misoperations as a primary component in nearly every wide area outage. This means concepts that are implicitly understood today will be immaterial in

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	the future. For example, it is easy to see that a CEA may assess a violation for a single missing relay operation evaluation out of hundreds that may have occurred during a wide-area weather event. Despite assurances that the CEA will take the circumstances “under consideration”, we are not convinced that that will always be the case. **Response:** Use of percentages is practical for assessing violations for fixed quantities; however, Protection System operations are variable and event driven. The drafting team constructed the VSL according to the NERC Violation Severity Level Guidelines. No change made. If the drafting team is reluctant to modify the definition of “Misoperation” or PRC-004-3’s requirements, there may be an opportunity to capture these understandings in a binding way in the RSAW. There is a new program that has been initiated by NERC to include Compliance representatives in the standards drafting process for situations just like these. If we are able to provide commentary on the auditors’ instructions captured in the RSAW, it would alleviate our doubts that understandings reached during the development phase would be retained when the standard becomes mandatory. **Response:** The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Xcel Energy	It is important to be able to see the draft RSAW, as it relates to what kind of evidence, if any, would be required to demonstrate accurate assessment of a slow trip. This could be particularly problematic, as not all have DME installed to be able to capture data to be able to measure both the start and stop of the operation.
Response: The drafting team thanks you for your comments. The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made.	

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The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). The proposed standard does not require an entity to have certain personnel and only specifies the performance required for Misoperation identification and correction. Entities with Protection Systems that are applicable to the standard are required to identify any Misoperation, determine its cause(s), and correct the cause(s) to prevent future occurrences. No change made.	
Los Angeles Department of Water and Power	LADWP recommends that the Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. LADWP also recommends that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation. **Response:** The NERC Glossary definition of Corrective Action Plan includes the phrase “remedy a specific problem”. In the context of this standard, the “problem” is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	

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Kansas City Power & Light	R2 requires a CAP except in cases where the entity can "Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability" R2 does not recognize that every CAP requires resources to complete and that the industry has limited resources. There are cases where the required resources to complete a CAP at multiple locations provides minimal increase in reliability. If these low productivity CAPs are required to be completed the net result is a decrease in BES reliability since other more productive work will not be done due to lack of resources. **Response:** Prompt identification of a Misoperation is important regardless of its perceived significance. Identifying a Misoperation and its cause(s) leads to preventing reoccurrence which, without correction, could lead to a reduction in reliability. Additionally, the identification of a Misoperation cause leads the entity to considering its other Protection Systems including other locations which may result in identifying and correcting a potential problem with another Protection System which may be significant to reliability. The standard provides options for entities to explain why actions were not taken. No change made. The entity should be able to state the CAP was completed at only the affected site and was not rolled out system wide due to poor ratio of resources required to reliability benefit gained. **Response:** An entity may elect not to address/correct the causes of Protection System Misoperations at other locations as there is no required performance at this time; however, the drafting team believes responsible entities will create a program to address other locations that is commensurate with its resources and impact to reliability. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Bonneville Power Administration	R2 requires each TO, GO, or DP to develop a corrective action plan, but it does not indicate which TO, GO, or DP must do this. Is this intended to be the TO, GO, or DP that owns the interrupting device or the TO, GO, or DP that owns the protection system?

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	BPA recommends the following wording for the beginning of R2: Each TO, GO, or DP that owns a component of a protection system identified as contributing to a misoperation, as determined per R1, shall within 60 calendar days of identifying the cause of each misoperation: (insert bullet points for R2). Similar to the comment above for R2, BPA believes that R3 does not make it clear which TO, GO, or DP the requirement applies to. BPA recommends that the entity identified by R1 as required to initiate the investigation of an interrupting device operation (BPA believes this should be the owner of the protective relays) should be the entity required to complete the actions in R3. BPA believes that similar to R2 and R3, R4 should be more specific about which TO, GO, or DP the requirement applies to. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made. The last paragraph of the Background section states that where PRC-004-WECC-1 overlaps with this continent-wide standard, entities are expected to comply with the more stringent standard. In our comments to the previous draft, BPA suggested that the Background section simply state which of the standards takes precedence instead of leaving it to the entities to determine which standard is more stringent. The response to this comment was that entities are required to comply with both the continent-wide standard and any applicable regional standards. This response seems to contradict the Background statement. BPA requests clarification on whether entities are expected to comply with both standards or only the more stringent standard, and

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	how an entity should determine which standard is more stringent as the standards cover very different issues. BPA believes that if an entity is expected to comply with both standards, that should be stated, or perhaps this part of the Background statement should be removed. **Response:** An entity in the Western Interconnection will be responsible for meeting the PRC-004-3 requirements and those in the regional standard PRC-004-WECC-1. The drafting team identified potential concerns between the standards and is proposing 12 additional calendar months for implementation of PRC-004-3. This is additional time to allow the Western Interconnection to revise its regional standard to correct an identified compliance overlap and any potential gaps in reliability. The drafting team removed the regional references to avoid confusion. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Wisconsin Electric Power Company	Since owners of BES Protection Systems will be required by this standard to review all operations, it would be helpful to define the term "Protection System operation", at least as it is used in this standard.
Response: The drafting team thanks you for your comments and contends that the phrase "Protection System operation" is a common industry phrase and does not need a definition. No change made.	
Southern Company - Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Mississippi Power Company; Gulf Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Southern Company supports the SERC comments and are including the following additional comments: 1. By using the definition of a Corrective Action Plan (CAP) in the NERC Glossary of terms as well as the term 'action plan' in R3, it is unclear what differences exist between a CAP and an "action plan" as written in PRC-004-3. Please modify language to be consistent or add language that describes the intent and difference between a CAP and an "action plan". **Response:** The concept of an action plan has been eliminated from the standard.

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	Change made. 2. R2 and R3 should be restructured such that it is immediately apparent that R2 deals with Misoperations with an identified cause and R3 deals with Misoperations without an identified cause. This could be accomplished by phasing that condition first in the requirement so that the required actions that are bulleted immediately follow the "shall" such as: "R2: For each Misoperation with an identified cause, the entity shall either develop a CAP ... or declare why ..." and "R3: For each Misoperation without an identifed cause, the entitiy shall either develop an action plan ... or declare why ..." **Response:** The concept of an action plan has been eliminated from the standard; however, the proposed Requirement R4 requires the entity to perform investigative action when circumstances require additional study or time to determine the cause(s) of a Misoperation. Requirement R5 and R6 respectively address CAP development and implementation by the Protection System component owner to correct the cause(s) of a Misoperation. Change made. 3. R4 should be re-structured to flow more smoothly, as follows; “R4. Each entity shall implement and revise, as needed, each CAP or action plan. **Response:** Requirements R5 and R6 (previously R2 and R4) now clearly delineate CAP development and implementation. Change made. 4. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration of making those three items the actual requirements? **Response:** The standard’s Requirements meet the intended objectives of the three bullets. No change made. 5. Please consider using the phrase "component that misoperated" rather than

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	"component that contributed to the misoperation" in the standard for clarity. **Response:** This clause was in the rationale box of the previous draft 3; however, Requirement R1 has been revised for clarification and does not use the phrasing "contributed to." Change made. 6. There is too much unnecessary date bookkeeping in the Requirements. We recommend deleting all existing date clocks linked to each event and specify a resolution time limit for investigative action plans/CAPs to be the filing date deadline for each quarter. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability. The establishment of investigative action plans and/or completion of necessary Corrective Action Plans in a timely fashion are the actions which will affect the reliability of the Protection System. **Response:** One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made. **Response:** The associated dates and timetables allow the Requirements to be measurable. No change made. 7. In reference to the above comment, if the timeframe are to remain, the SDT is strongly encouraged to move toward an internal controls format for this standard. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of

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	instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Entergy Services, Inc. (Transmission)	Suggest "Composite Protection System" as listed in the Guidelines and Technical Basis section (page 14 of 24) be a defined term for this standard.
Response: The drafting team thanks you for your suggestion. The drafting team is proposing a definition for the term "Composite Protection System." Change made.	
Northeast Power Coordinating Council	The Compliance Section of Standard has "The Transmission Owner, Generator Owner and Distribution Provider that owns a BES Protection System shall retain evidence for all Misoperations with an open investigation, action plan, or CAP even if the BES interrupting device operation occurred prior to the current audit period." The word "open" should precede not only investigation, but action plan and CAP for clarity. It should be made to read "open investigation, open action plan, or open CAP even if the BES interrupting device operation occurred prior to the current audit period". **Response:** The evidence retention section has been revised to require evidence to be retained a defined period after the completion. This would include any "open" CAPs and other ongoing performance of the standard. Change made. What is an Entity's compliance obligation for an open investigation or open action plan that occurred prior to regulatory approval of this Standard but in the current audit period of an entity? **Response:** The entity must be compliant with the standard that was enforceable at the time through the transition (implementation) of the new standard. No change made. The new standard establishes specific time limits. If an entity has an operation to investigate the day prior to the compliance obligation date, does the 120 day time limit

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	apply the day the Standard is obligatory? **Response:** No. The new standard will only apply from the effective date forward. No change made. Regarding the Implementation Plan for Requirements R1, R2, R3 and R4: "Entities shall be 100% compliant for any new Protection System Operation on the first day of the first calendar quarter twelve months" (this is the compliance obligation date) "following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twelve months following Board of Trustees adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard." In this section of the Implementation Plan, what is meant by "new"? Is "new" any operation that occur after the compliance obligation date, or during the window of implementation between regulatory approval and compliance obligation date? **Response:** The reference to "new" has been removed. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
ExxonMobil Research and Engineering	The documentation requirements for maintaining a database of every operation of a BES interrupting device, which are laid out in Measure M1, represent a significant step change in documentation requirements when compared with the current misoperation analysis and reporting requirements. Unintentional mismanagement of a database that identifies every operation by time, date, and date of review during a six year audit window poses no significant risk to the reliabile operation of the Bulk Electric System. However, enforcement of this measure will likely identify clerical or other unintentional errors made during the process of tracking misoperations that will impede NERC's ability to address violations that pose a moderate or severe threat to the reliability of the Bulk Electric System. The underlying objective of the data compiled in the measure appears to be a 'best

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	practice' method for retaining data necessary to meet the quarterly reporting requirements for misoperation reporting; specifically reporting of the 'total number of operations'. While it is understood, that NERC is utilizing this quarterly reporting data to develop metrics to track the performance of BES Protective Systems, the required implementation of a prescriptive tracking method in a Reliability Standard does not balance the need and method for addressing the need, and compliance with the quarterly reporting of misoperation data is already driven by NERC's Rules of Procedure. The SDT should consider modifying Measure M1 in such a way that it requires misoperation analysis reports (Corrective Action Plans and Action Plans) to include the level of detail addressed in Measurement M1 (time & date of operation, date analysis determined it was a misoperation, etc.). This modification would address the need to ensure that misoperations are appropriately analyzed within a reasonable amount of time while avoiding the implementation of a Reliability Standard requirement that could create enforcement actions that hinder NERC's ability to address potential violations that pose a moderate or serious threat to the Bulk Electric System.
Response: The drafting team thanks you for your comments and notes that Measures are not enforceable. Measures provide examples of evidence that may be used to demonstrate compliance with the requirements. The drafting team removed all of the reporting requirements from the proposed standard. The data will be collected through the NERC Rules of Procedure, Section 1600, Request for Information or Data process. Metrics will be developed by NERC for reliability assessments, for example. The requirements and associated time frames ensure that the responsible entities are diligent about Misoperation identification, CAP development and completion. No change made.	
PPL NERC Registered Entities	The PPL NERC Registered Entities (PPL Electric Utilities, PPL Generation LLC, PPL Energy Plus, LG&E and KU Services) are in agreement with the spirit of the North America Generator Forum Standards Review Team comments for the successive ballot for Project 2010-05.1 Protection Systems: Misoperations. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date

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	deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation identification, CAP development and completion. Having time periods accounts for seasonal workloads and unforeseen issues with implementing a CAP. The timetables make the requirements auditable. No change made. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. **Response:** The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made. The three bullets found at the top of page 6 of draft 3 of the standard are possibly sufficient requirements for this standard. Has any consideration been given to making those three items the actual requirements? **Response:** The standard's Requirements meet the intended objectives of the three bullets. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Liberty Electric Power LLC	The standard would be simplified by combining R1 through R4 to state: R1 For each activation of a BES interrupting device initiated by a Protection System, the

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	entity shall identify the cause of the operation. R1.1 If the activation is determined to be a misoperation, the entity shall develop a corrective action plan, or explain in a declaration why a CAP cannot reasonably be instituted. R1.2 If no cause can be determined, the entity shall develop an action plan for further investigation, or explain in a declaration why no further action is warranted. R1.3 All action plans shall be developed within 180 days of the operation, or notification of an operation of a BES interrupting device caused by the RE's Protection System. R2 All action plans developed under R1 shall be implemented or revised as needed until complete. **Response:** The standard has been revised to provide one activity for a single reliability goal in accordance with standard drafting guidelines. The drafting team restructured the previous requirements into separate requirements. Change made. The additional detail in the current version (work timetables, other facilites) should be moved to the measures, as they are the output of the requirements. **Response:** Examples of CAPs are provided in the Application Guidelines. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Essential Power, LLC	There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. **Response:** One of the objectives of this project is to bring consistency to metrics

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	through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made. **Response:** The associated dates and timetables allow the Requirements to be measurable. No change made. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. **Response:** The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements? **Response:** The standard's Requirements meet the intended objectives of the three bullets. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Cogentrix Energy Power Management, LLC	There is too much bookkeeping required in the Requirements. We recommend deleting all date clocks linked to each event and replace them with a final resolution time limit for action plans/CAPs and/or replace them with a filing date deadline to identify, review, and disposition of each operation for each event. The establishment of

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	multiple time frames for each detail of a Protection System operation will not improve reliability; the completion of any necessary Corrective Action Plans are the actions which will affect the reliability of the Protection System operations. **Response:** One of the objectives of this project is to bring consistency to metrics through the Section 1600 data request. In conjunction with data reporting, the proposed definition of Misoperation will improve identifying the appropriate category of Misoperation. The drafting team agrees that a results-based approach using metrics could simplify the standard and reduce compliance burdens; however, it may take several years of data collection to develop consistent and meaningful metrics for measure performance. No change made. The associated dates and timetables allow the Requirements to be measurable. No change made. In various locations of the draft, Protection System misoperations are discounted as misoperations for situations where other redundant protection may have adequately operated. In these instances, perhaps the classification should be changed to non-reportable misoperation rather than simply that they are not Misoperations. **Response:** The composite Protection System is the collective operation of the entire Protection System for an Element which is included in determining whether a Misoperation occurred. To clarify the usage of the terminology, the drafting team is proposing the definition "Composite Protection System" which has an exclusion for backup protection provided by a remote Protection System. Change made. The three bullets found at the top of page 6 of draft 3 of the standard should be the three requirements of this standard. Has any consideration been given to making those three items the actual requirements? **Response:** The standard's Requirements meet the intended objectives of the three bullets. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	

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Pepco Holdings Inc & Affiliates	To avoid confusion, Requirements R2, R3, and R4 should be re-worded to make it clear that they apply only to those entities whose Protective System misoperated and not to the interrupting device owner. The following language is suggested: R2. "Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall within 60 calendar days of identifying the cause of each Misoperation..." R3. "Each Transmission Owner, Generation Owner, or Distribution Provider shall, within 180 calendar days of the interruption of the BES Facility due to a Protective System Misoperation, complete for each Misoperation without an identified cause...." R4. "Each Transmission Owner, Generation Owner, or Distribution Provider, whose Protection System misoperated, shall implement each CAP or action plan, and revise as needed through completion."
Response: The drafting team thanks you for your comments. Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.	
Texas Reliability Entity	We are concerned that the applicability of the Standard limits the misoperation analysis only to BES Element Protection Systems. Under the new BES definition and guidance documents, there will be numerous examples of misoperations on non-BES Element Protection Systems which could have a major impact on the BES when the fault must be cleared by remote backup relays. Example: Consider a 50MVA generator connected to a substation via a radial line. Under the new BES guidance, the generator is part of the BES while the interconnecting radial line would not be part of the BES under exclusion E1(b). If a fault occurs on the non-BES radial line and the Protection System fails to trip, the fault must then be

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	cleared by either local or remote backup relays at the interconnecting substation(s). Under this scenario with the current proposed PRC-004 requirements, the owner of the non-BES radial line has no obligation to analyze or correct the Misoperation. The PRC-027 SDT received comments with similar concerns in its last revision. They have drafted language to ensure that coordination of non-BES Protection Systems between different Functional Entities. The PRC-004 SDT may want to consider similar language to ensure that all Misoperations which can affect the reliable operation of the BES are analyzed and corrected.
Response: The drafting team thanks you for your comment. The standard addresses the Misoperation of Protection Systems for BES Elements. If the Composite Protection System operated correctly in backing up the failure of a non-BES Element, the operation would be considered correct. If the Composite Protection System failed to operate correctly for the non-BES Element fault, that would be considered a Misoperation. No change made.	
JEA	We believe that the issues should be handled through modification of PRC003 not PRC004.
Response: The drafting team thanks you for your comment. In FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004; therefore, PRC-003-1 will be retired. No change made.	
seattle city light	We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and

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	breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. We would also suggest that the ICP include specifications that the entity identify mitigating factors performed under the CAP that specifically address the Misoperation. **Response:** The NERC Glossary definition of Corrective Action Plan includes the phrase "remedy a specific problem". In the context of this standard, the "problem" is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Sacramento Municipal Utility District	We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation.

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	Response: The NERC Glossary definition of Corrective Action Plan includes the phrase "remedy a specific problem". In the context of this standard, the "problem" is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Public Utility District No. 1 of Snohomish County	We would like to reiterate our previous comments that this Drafting Team give due weight to the Internal Controls Process (ICP). We believe the responsible entity should be allowed the latitude to determine the Corrective Action Plan (CAP) that follows the ICP approach. **Response:** The drafting team continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made. We would also suggest that the standard include specifications that the entity identify mitigating factors performed under the CAP that specifically address the misoperation. **Response:** The NERC Glossary definition of Corrective Action Plan includes the phrase "remedy a specific problem". In the context of this standard, the "problem" is the cause a Misoperation. Mitigating actions may be included as a part of the CAP. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Southwest Power Pool Reliability Standards	We would like to see a RSAW for this particular standard to better understand what

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Development Team	level of review and or evidence, if any, auditors will require to determine that you assessed your operations adequately for R1. **Response:** The drafting team anticipates posting a draft PRC-004-3 RSAW so that entities will have an opportunity to consider auditing approaches. Posting is expected mid-way through the draft 4 posting of PRC-004-3. No change made. For instance if you didn't have certain monitoring equipment that captures data for protection system elements, then the data available would be limited for assessing slow trips. **Response:** The slow trip category is included because it is a type of Misoperation which should be identified when possible. In cases where the entity does not have access to Disturbance Monitoring Equipment (DME), a slow trip may be revealed by BES instability and tripping of more than then minimum Element(s). The proposed standard does not require the installation of DME which is being addressed by Project 2007-11 – Disturbance Monitoring (PRC-002 and PRC-018). No change made. Depending upon the guidance requested in the SPP comments (what will be required to prove that all faults have been analyzed) the time frames may become difficult to maintain especially during storm seasons. **Response:** The *Sanction Guidelines of the North American Electric Reliability Corporation*, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, including specific language in the proposed standard complicates a low frequency event where a compliance violation might occur. No change made. Likewise, the 60 days required to develop a corrective action once the cause is determined could become difficult for severe or extreme events. In extreme cases dynamic power flow models may need to be developed and applied to system studies

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	before the CAP can be developed. **Response:** The CAP by definition is a set of actions and a timetable to remedy a specific problem (i.e., Misoperation cause). In this case, the entity would include performing dynamic power flow simulations as an action within the CAP. Similarly, the timetable would account for the time needed to perform the simulation. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by Florida Municipal Power Agency and has a couple of additional comments. Since the comment document is not formatted for this purpose, we will submit them here. The standard is titled Protection System Misoperation Identification and Correction, not Operation Identification and Submittal. IMPA does see that an organzation might keep track of operations but to require this action by a standard requirement and then potentially find an enitity in non-compliance is over reaching for this Protection System Misoperation standard. In order to be in compliant with this stadnard, an entity should only be required to perform the action of Protection System Misoperation Identification and Correction which is the standard title. **Response:** Each entity must review its Protection System operations according to Requirement R1 (including R3) in order to identify potential Misoperations. Without that requirement, there is no measure whether or not the entity reviewed the necessary operations. No change made. Another problematic area involves the "same 120 day period of a BES interrupting device operation caused by a Protection System operation". What happens if the owner of the Protection System component is notified toward the end of the 120 day period of a BES interrupting device operation (say 119 day) and there is not sufficient time for an investigation by the Protection System owner into the cause of the trip? The Protection System owner should not be found non-compliant for requirement 1.2 if not enough time is given to them to properly investigate the reason for the operation of

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	the Protection System. **Response:** Requirement R1 was split into two separate Requirements (R1 and R3) to provide clarity on the BES interrupting device Protection System owners' responsibilities (R1) following the operation of the BES interrupting device to identify any Misoperation. In cases where a Protection System owner is notified to review its Protection System components (R3), time has been allocated (i.e., the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation) to that owner to investigate the operation and make a determination whether its Protection System component(s) caused a Misoperation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.	
Western Electricity Coordinating Council	WECC believes that an Internal Controls Process with Risk Based requirements should be implemented in this standard.
Response: The drafting team thanks you for your comments and continues to support the proposed standard as currently structured. The draft requirements allow Compliance Enforcement Authorities to take into account use of internal controls in connection with monitoring activities. However, internal controls are only a mechanism to help auditors determine the depth and breadth of testing as it pertains to compliance with the related Reliability Standard and specific requirements and when necessary understand the facts and circumstances of instances of potential non-compliance. How any possible violations may be treated is outside of the scope of the project and reserved to the enforcement process. No change made.	

END OF REPORT

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. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft 4 of PRC-004-3 – Protection System Misoperation Identification and Correction 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).

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Ballot	January 2014
10-day Final Ballot	March 2014
BOT Approval	May 2014

Effective Dates

Except in the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months 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. Except in the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

In the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months 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. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	New

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 *Glossary of Terms used in NERC Reliability Standards* are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the glossary.

Composite Protection System:

The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.

Misoperation:

The failure of a Composite Protection System to operate as intended. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
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 for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.[1]

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key element for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of

[1] For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a “fill-in-the-blank” standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information (“data request”). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. **Effective Dates:** See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

M1. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This requirement ensures that entities review those Protection System operations meeting the criteria in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner has the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and

2.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.3 The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

M2. Acceptable evidence for Requirement R2, including Parts 2.1, 2.2, and 2.3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: This requirement ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System when the criteria in all three Parts (2.1, 2.2, and 2.3) are met, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that the three conditions are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Acceptable evidence for Requirement R3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Acceptable evidence for Requirement R4 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Acceptable evidence for Requirement R5 may include, but is not limited to, the following documentation (electronic or hardcopy format): a dated CAP or a dated declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation in lieu of a CAP and for future reference.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Acceptable evidence for Requirement R6 may include, but is not limited to, the following documentation (electronic or hard copy format): dated records that document the implementation of each CAP and the completion of actions for each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: The CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following completion of each CAP, evaluation, and declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[2] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[3]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[4]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[2] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf
[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf
[4] "Transmission Protective Relay System Performance Measuring Methodology," Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, 1999.

For reference, a “Protection System” is defined in the *Glossary of Terms used in NERC Reliability Standards* (“NERC Glossary”) as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of the Protection System(s) that function collectively to protect a Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.*

This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition.

> **Misoperation –** *The failure a Composite Protection System to operate as intended. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault –** *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault –*** *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.*

Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended. The definition includes six categories which provide further differentiation and examples of what is a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a Misoperation as long as another component of the transformer's Composite Protection System operated to clear the Fault.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first would not in and of itself be a Misoperation.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as another component of the generator's Composite Protection System operated as intended (e.g., isolating the generator).

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line Fault is a Misoperation.

Installing high-speed protection may be a part of a utility’s standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a “Slow Trip – During Fault” of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.

The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

Slow Trip – Other Than Fault

The phrase “slower than required” means the Composite Protection System operated slower than the objective of the owner(s). It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation. This category of Misoperation could result in equipment damage.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the Faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to, power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6d:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation.

The "on-site" activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements, are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

The above are examples only, and do not constitute an all-inclusive list of conditions that would not be a Misoperation.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement R1

This requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified that its Protection System component(s) as causing the BES interrupting device operation.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner’s differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Requirement R2

For Requirement R2 (i.e., case of multi-entity ownership), the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) when the criteria in Requirement R2 is met.

This requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking or DCB relaying on 03/03/2014 at 15:43 UTC during an external fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the latter half of the 120 calendar days allotted to the BES interrupting device owner.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, the entity is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, or requesting a necessary outage.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause.

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

Example R4b: All relays at station A and B functioned properly during testing on 08/26/2014. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

Example R4c: The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan or CAP is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must create the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation; in these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAPs to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The time periods within Requirement R1, R3 and Requirement R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection

Systems at other locations or the reasoning for not taking any action. The CAP must include an evaluation of other Protection Systems including other locations to be complete.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer Fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following in an example of a declaration made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase fault. The protection scheme utilized for both protection groups is a POTT. The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. The failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. The failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay; and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. The failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due resource rescheduling from 02/01/15 to 03/01/2015. Following the timetable change, capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem; and preemptive actions for similar installations. (See also, Example R5d).

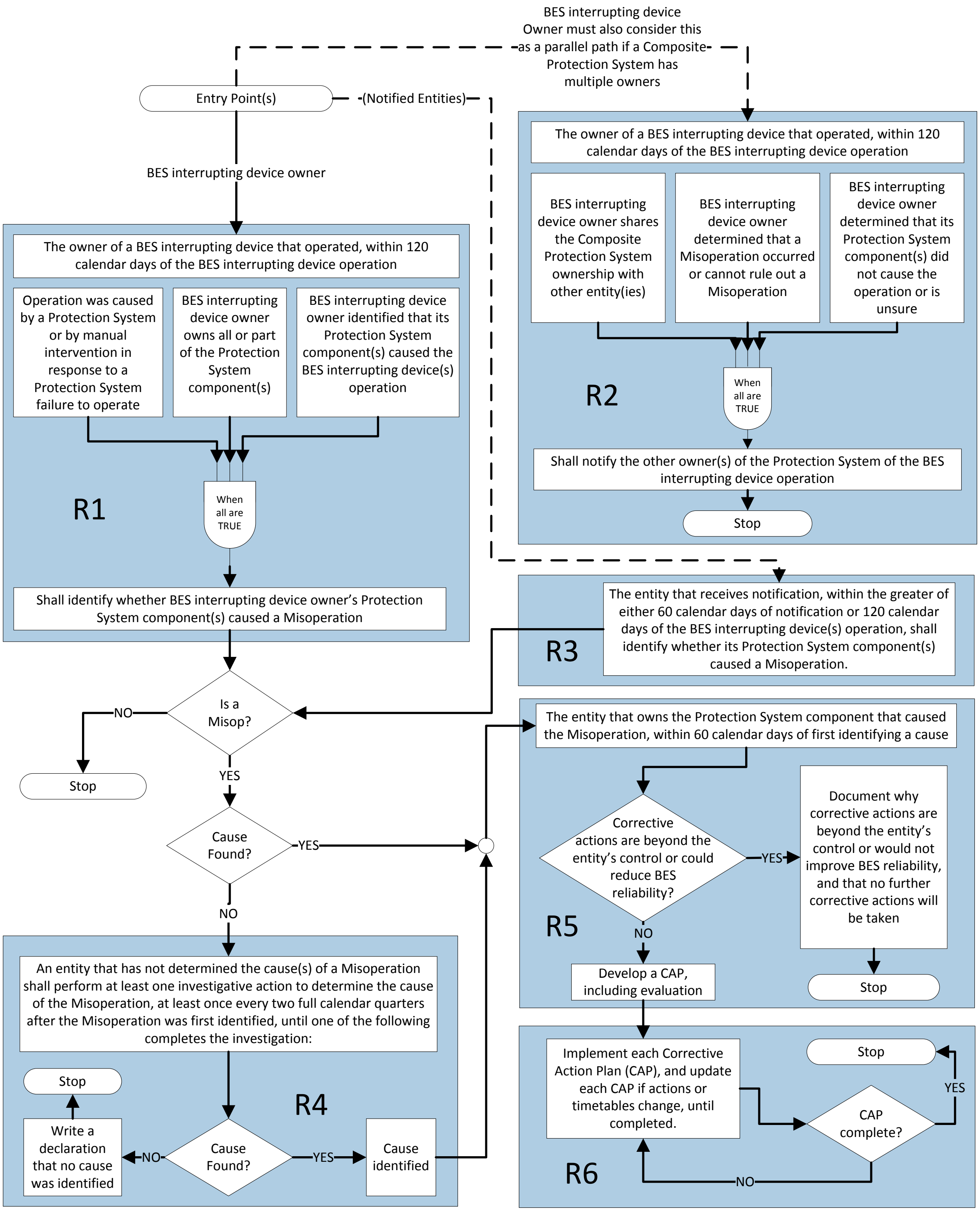
Example R6d: Actions: Fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all the documented actions to resolve the specific problem (i.e., Misoperation) are completed which may include those actions resulting from the entity’s evaluation of other locations, if not addressed through a separate CAP.

Process Flow Chart: Below is a graphical representation of the expected process created by the standard, including the relationships between requirements:



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. The SC authorized moving the SAR forward ~~to~~for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day ~~concurrent~~formal comment ~~and initial ballot~~ period from July 25 – September 7, 2012~~.~~ and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft ~~3~~4 of PRC-004-3 ~~posted –~~ Protection System Misoperation Identification and Correction for a ~~30~~45-day ~~formal~~ comment period ~~with parallel successive~~and ballot~~.~~ in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
~~30~~Additional 45-day Formal Comment Period with ~~Successive~~Parallel Ballot	January~~,~~ 201~~3~~4
~~Recirculation ballot~~10-day Final Ballot	~~February, 2013~~March 2014
BOT Approval	May~~,~~ 201~~3~~4

Effective Dates~~: First day of~~

Except in the ~~first calendar quarter that is twelve months beyond the date that this~~ Western Interconnection, the standard ~~is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes~~and definitions shall become effective on the first day of the first calendar quarter that is twelve months ~~beyond the date this standard is approved by~~ 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. Except in the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable~~ provided for in that jurisdiction.

In the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months 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 ~~such ERO governmental authorities~~go into effect. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)	New

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 *Glossary of Terms used in NERC Reliability Standards* ~~*Glossary of Terms*~~ are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the ~~*G*~~glossary.

Composite Protection System:

> The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.

Misoperation:

> The failure of ~~an Element's composite~~a Composite Protection System to operate as intended. Any of the following is ~~*considered*~~ a Misoperation:

1. **Failure to Trip ~~-~~– During Fault ~~-~~–** A failure of a Composite Protection System to operate for a Fault ~~within the zone~~ condition for which it is designed~~ to protect~~. The failure of a Protection System component is not a Misoperation as long as the ~~overall~~ performance of the Composite Protection System ~~for the Element it is designed to protect~~ is correct.
2. **Failure to Trip ~~-~~– Other Than Fault ~~-~~–** A failure of a Composite Protection System to operate for a non-Fault condition for which ~~the Protection System was intended to operate~~it is designed, such as a power swing, ~~under-voltage, over excitation~~undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the ~~overall~~ performance of the Composite Protection System ~~for the Element it is designed to protect~~ is correct.
3. **Slow Trip ~~-~~– During Fault ~~-~~–** A Composite Protection System operation that is slower than ~~intended~~required for a Fault ~~within the zone~~ condition for which it is designed~~ to protect~~. Delayed ~~Fault~~ clearing ~~associated with an installed high-speed protection scheme is not~~ of a Fault condition is a Misoperation if ~~the~~ high-speed performance ~~has not been~~was previously identified ~~to meet the~~ as being necessary to prevent voltage or dynamic ~~stability performance requirements of the TPL standards nor is it required to ensure coordination with~~instability, or resulted in the operation of any other Composite Protection System~~s~~.
4. **Slow Trip ~~-~~– Other Than Fault ~~-~~–** A Composite Protection System operation that is slower than ~~intended~~required for a non-Fault condition for which it is designed, such as a power swing, ~~under-voltage, over excitation~~undervoltage, overexcitation, or loss of excitation~~ for which the Protection System was intended to operate~~. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.

5. **Unnecessary Trip ~~-~~– During Fault** ~~- A~~ An unnecessary Protection System operation for a Fault ~~for which the Protection System is not intended to operate.~~ condition on another Element.

6. **Unnecessary Trip ~~-~~– Other Than Fault** ~~- A~~ An unnecessary Protection System operation for a non-Fault condition for which ~~the~~it is not designed. A Protection System ~~is not intended to operate, and~~operation that is ~~unrelated to~~caused by on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

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 Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) ~~Protection Systems~~Elements.
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 for BES Elements

~~**4.2.2** Underfrequency Load Shedding (UFLS) that trips a BES Element~~

~~**4.2.3** Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded~~

~~4.2.4~~4.2.1 . Non-protective functions that ~~may be imbedded~~are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.[1]

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are not included in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key element for BES reliability is the correct performance of Protection Systems. ~~Monitoring BES~~The monitoring of Protection System events for BES Elements, as well

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations~~ with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. ~~. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems ~~required the Regions~~requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-~~2a.~~ 2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-~~2a~~2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not ~~usable~~optimal to establish consistent metrics for measuring Protection System performance. As such, the ~~drafting team is removing the~~ data reporting obligation ~~from the~~for this standard is being removed and is ~~developing a data request~~being developed under ~~Section 1600 of~~ the NERC Rules of Procedure~~.~~, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry.~~ The data submitted as part of the data request will not be used for compliance or enforcement purposes. The~~ The removal of the data collection obligation from the standard does not result in a reduction of reliability~~ as Responsible Entities are required to retain~~. The standard and data request have been developed in a manner such that evidence ~~of~~used for compliance ~~for audit and compliance purposes under the Compliance Section C 1.2 Evidence Retention portion of~~with the standard and data request are intended to independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- ~~•~~ Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- ~~•~~ Analyze Misoperations of Protection Systems for Facilities that are part of the BES to ~~determine~~identify the cause(s).
- ~~•~~ Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations ~~of or~~ associated with Special Protection Schemes~~,~~, (SPS) and Remedial Action Schemes~~, and Under-Voltage Load Shedding~~ (RAS) are not addressed in this standard due to their inherent complexities. NERC ~~intends~~plans to ~~address these areas through future projects~~handle SPS and RAS in the second phase of this project.

~~Note that the WECC~~The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths~~ and Remedial Action Schemes. In those cases where PRC-004-~~. The WECC~~-1 overlaps with the Continent-wide~~ region plans to conduct work to harmonize the regional standard~~, entities are expected to comply with the more stringent~~ with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. Effective Dates: See Implementation Plan

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider ~~shall~~that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

~~**1.1** Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.~~

- ~~If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation.~~
- ~~If the entity owns the~~**1.1** The BES interrupting device ~~but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.~~

~~**Rationale for R1**: This requirement is the first step to ensuring that practices for reviewing and classifying Protection System operations and correcting Misoperations are consistently employed. The drafting team believes 120 calendar days takes into account the seasonal nature of Protection System operations; both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal. This requirement mandates entities identify and review Protection System operations. Risks to the BES caused by Misoperations are reduced by reviewing all Protection System operations and investigating any Misoperations to find their cause(s). Requirement R1 places the responsibility on the BES interrupting device owner to investigate operations initiated by a Protection System. The initial investigation documentation should be provided to the owner of the Protection System component(s) that contributed to the Misoperation, upon request. The owner of the interrupting device and the entity that owned the component that contributed to the Misoperation should be communicating about the operation before this notification is transmitted. The owner of the component that contributed to the Misoperation will create the CAP, action plan or declaration required by Requirements R2 and R3.~~

- ~~The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.~~

~~Within the same 120 day period of a BES interrupting device operation~~ operation was caused by a Protection System ~~operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.~~or by manual intervention in response to a Protection System failure to operate; and

~~**M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Part 1.1 that may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date and time of each applicable interrupting device operation and indicates when each related Protection System operation was reviewed. Acceptable evidence for the notification required by Part 1.1 may include, but is not limited to, emails, electronic files, or hard copy records demonstrating transmittal of information. Acceptable evidence for Part 1.2 may include, but is not limited to, dated lists, logs, or a database (electronic or hard copy format) that documents the date, time, Facility and equipment name associated with each Misoperation, a copy of a dated Misoperation investigation report or documented findings, which may include sequence of events, relay targets, summary of DME records for each Misoperation.~~

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

M1. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This requirement ensures that entities review those Protection System operations meeting the criteria in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner has the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and

2.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.3 The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

~~**Rationale for R2**: A formal CAP is a proven tool for resolving operational problems. Based on industry experience and operational coordination timeframes, the SDT believes 60 calendar days is reasonable for considering such things as alternative solutions, coordination of resources, or development of a schedule for a CAP. When the cause of a Misoperation is determined from implementing an action plan in accordance with Requirement R4, a CAP must be developed in accordance with Requirement R2.~~

~~In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation investigation process and for future reference.~~

M2. Acceptable evidence for Requirement R2, including Parts 2.1, 2.2, and 2.3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: This requirement ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System when the criteria in all three Parts (2.1, 2.2, and 2.3) are met, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that the three conditions are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, ~~or~~and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Acceptable evidence for Requirement R3 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

~~**Rationale for R3**: Where a Misoperation cause is not determined during the initial investigation; implementing an action plan of additional investigation/monitoring may determine a cause and lead to the development of a CAP in accordance with Requirement R2. The 180 calendar day period is the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)~~

~~If the action plan completion does not provide direction for identifying the cause, then pursuing further action is not warranted. In these cases, documenting the reasons is essential for justifying the close of the Misoperation investigation process and for future reference.~~

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Acceptable evidence for Requirement R4 may include, but is not limited to, the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying ~~the~~a cause of ~~each~~the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s~~) that includes~~), and an evaluation of the CAP's applicability to the entity's other Protection Systems ~~at~~including other locations, or
- Explain in a declaration why corrective actions are beyond the entity's control or would ~~reduce~~not improve BES reliability, and that no further corrective actions will be taken.

~~**M2**~~**M5.** Acceptable evidence for Requirement R5 may include, but is not limited to, the following documentation (electronic or hardcopy format): a dated CAP or a dated declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for justifying the close of the Misoperation in lieu of a CAP and for future reference.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~have evidence for Requirement R2 that must include a dated CAP or a dated declaration explaining why there is no need to develop a CAP.~~

~~Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause:~~implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. [*Violation Risk Factor: Medium*~~] [~~*][Time Horizon: Operations Planning, Long-Term Planning]*

- ~~Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or~~
- ~~A declaration explaining why no further actions will be taken.~~

~~**M3.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence for Requirement R3 that must include a dated action plan or a dated declaration.~~

~~**R1.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion. [*Violation Risk Factor: High*] [*Time Horizon: Operations Planning, Long-Term Planning*]~~

~~**Rationale for R4**: The CAP or action plan must be completed to accomplish all identified objectives. During the course of implementing a CAP or action plan, revisions may be necessary for a variety of reasons such as scheduling conflicts or resource issues. Documenting the CAP or action plan provides auditable progress and completion confirmation on any plan. When the cause of a Misoperation is determined from implementing an action plan, a CAP must be developed in accordance with Requirement R2.~~

~~**M4.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have~~**M6.** Acceptable evidence for Requirement ~~R4 that must~~R6 may include, but is not limited to, ~~dated~~ the following documentation (electronic or hard copy format): dated records ~~which~~that document the implementation of each CAP and ~~action plan and~~ the completion of actions for each CAP ~~or action plan. The evidence~~. Evidence may also include ~~dated~~ work management program records, ~~dated~~ work orders, ~~or dated~~and maintenance records.

Rationale for R6: The CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority ~~(CEA)~~

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 CEA 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 ~~that owns a BES Protection System~~ shall keep data or evidence to show compliance ~~with Requirements R1, R2, R3, and R4 and Measures M1, M2, M3, and M4, since the last audit~~as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider ~~that owns a BES Protection System~~ shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for ~~all Misoperations with an open investigation, action plan, or~~ 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following completion of each CAP ~~even if the BES interrupting device operation occurred prior to the current audit period~~, evaluation, and declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner ~~and~~, or Distribution Provider ~~that owns a BES Protection System~~ is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes~~:~~

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R1~~ **R2**	Operations Assessment, Operations Planning	Medium	The responsible entity ~~performed~~notified the ~~actions~~other owner(s) of the Protection System component(s) in accordance with Requirement ~~R1, Parts 1.1 and 1.2~~ R2, but in more than 120 calendar days ~~but~~and less than or equal to 150 calendar days of the ~~operation's occurrence.~~ ~~OR~~ ~~The responsible entity identified a Protection System operation that operated one of its~~ BES interrupting ~~devices but failed to review the operation in accordance with Requirement R1, Part 1.1.~~ ~~OR~~ ~~The responsible entity completed its review of a Protection System operation that operated one of its BES interrupting devices in 120 calendar days and~~	The responsible entity ~~performed~~notified the ~~actions~~other owner(s) of the Protection System component(s) in accordance with Requirement ~~R1, Parts 1.1 and 1.2~~ R2, but in more than 150 calendar days ~~but~~and less than or equal to ~~160~~165 calendar days of the ~~operation's occurrence~~BES interrupting device operation.	The responsible entity ~~performed~~notified the ~~actions~~other owner(s) of the Protection System component(s) in accordance with Requirement ~~R1, Parts 1.1 and 1.2~~ R2, but in more than ~~160~~165 calendar days ~~but~~and less than or equal to ~~170~~180 calendar days of the ~~operation's occurrence~~BES interrupting device operation.	The responsible entity ~~performed the actions~~ notified the other owner(s) of the Protection System component(s) in accordance with Requirement ~~R1, Parts 1.1 and 1.2~~ R2, but in more than ~~170~~180 calendar days of the ~~operation's occurrence~~BES interrupting device operation. OR The responsible entity failed to ~~identify and review a Protection System operation that operated~~ notify one ~~of its BES interrupting devices~~or more of the other owner(s) of the Protection System component(s) in accordance with Requirement ~~R1, Part 1.1.~~ ~~OR~~ ~~The responsible entity~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
~~R2~~ **R5**	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement ~~R2,~~R5, but in more than 60 calendar days ~~but~~and less than or equal to 70 calendar days ~~following the identification~~ of ~~the~~first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement ~~R2,~~R5, but in more than 70 calendar days ~~but~~and less than or equal to 80 calendar days ~~following the identification of the~~first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement ~~R2,~~R5, but in more than 80 calendar days ~~but~~and less than or equal to 90 calendar days ~~following the identification~~ of ~~the~~first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement ~~R2,~~R5, but in more than 90 calendar days ~~following the identification~~ of ~~the~~first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or ~~make~~explain in a declaration in accordance with Requirement ~~R2.~~R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R3~~ R5	~~Operations Planning, Long-Term Planning~~(Continued)	~~Medium~~	The responsible entity developed an ~~action plan, or made a declaration~~evaluation in accordance with Requirement ~~R3,~~R5, but in more than ~~180~~60 calendar days ~~but~~and less than or equal to ~~210~~70 calendar days ~~following~~of first identifying a cause of the ~~associated BES interrupting device operation~~Misoperation.	The responsible entity developed an ~~action plan, or made a declaration~~evaluation in accordance with Requirement ~~R3,~~R5, but in more than ~~210~~70 calendar days ~~but~~and less than or equal to ~~220~~80 calendar days ~~following~~first identifying a cause of the ~~associated BES interrupting device operation~~Misoperation.	The responsible entity developed an ~~action plan, or made a declaration~~evaluation in accordance with Requirement ~~R3,~~R5, but in more than ~~220~~80 calendar days ~~but~~and less than or equal to ~~230~~90 calendar days ~~following~~of first identifying a cause of the ~~associated BES interrupting device operation~~Misoperation.	The responsible entity developed an ~~action plan, or made a declaration~~evaluation in accordance with Requirement ~~R3,~~R5, but in more than ~~230~~90 calendar days ~~following~~of first identifying a cause of the ~~associated BES interrupting device operation~~Misoperation. OR The responsible entity failed to develop an ~~action plan or a declaration~~evaluation in accordance with Requirement ~~R3~~R5.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~R4~~ R6	Operations Planning, Long-Term Planning	~~High~~Medium	The responsible entity implemented, but failed to ~~revise~~update a CAP, when actions or ~~action plan as needed~~timetables changed, in accordance with Requirement ~~R4~~R6.	N/A	N/A	The responsible entity failed to implement a CAP ~~or action plan~~ in accordance with Requirement ~~R4~~R6.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[2] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[3]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

~~The composite Protection System in the context of this standard is the total complement of protection for a system Element. All protection for a given Element such as primary, secondary, backup, pilot and non-pilot relay schemes are included in the composite Protection System for the Element. These individual schemes or systems may be isolated or function independently, but aggregate as part of one composite Protection System.~~

~~A Protection System~~

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[4]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[2] http://www.nerc.com/news_pr.php?npr=723[2] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf

[4] "Transmission Protective Relay System Performance Measuring Methodology," Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, 1999.

For reference, a "Protection System" is defined in the ~~NERC~~ *Glossary of Terms* ~~as:~~ *used in NERC Reliability Standards* ("NERC Glossary") as:

- ~~•~~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.

~~Circuit breaker and other~~A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System~~.~~

~~A revised~~ , the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation~~ definition is~~ .

The following two definitions are being proposed for ~~industry adoption;~~inclusion in the ~~failure~~ NERC Glossary:

> **Composite Protection System –** *The total complement of* ~~an Element's~~*the Protection System(s) that function collectively to protect a Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.*

This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition.

> **Misoperation –** *The failure a Composite Protection System to operate as intended.* ~~The definition includes~~*Any of the following* ~~categories~~*is a Misoperation*:
>
> 1. ~~**(1)**~~**Failure to Trip – During Fault –** *A failure of a Composite Protection System to operate for a Fault* ~~**within the zone**~~*condition for which it is designed*~~**to protect.**~~ *. The failure of a Protection System component is not a Misoperation as long as the* ~~**overall**~~ *performance of the Composite Protection System is correct.*

***Failure to Trip – Other Than Fault –** A failure of a Composite Protection System to operate for* ~~**the Element**~~*a non-Fault condition for which it is designed* ~~**to protect is correct.**~~

2. ~~A failure of a transformer's composite Protection System to operate for a transformer Fault is an example of a "~~, *such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure* ~~to trip" Misoperation. This type~~*of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*

4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.*

5. ***Unnecessary Trip – During Fault*** *– An unnecessary Protection System operation for a Fault condition on another Element.*

6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.*

Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended. The definition includes six categories which provide further differentiation and examples of what is a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation~~s~~.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.

> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a ~~"failure to trip"~~ Misoperation as long as another component of the transformer's ~~c~~Composite Protection System operated to clear the Fault~~. Please see category 3 to see if the "slow trip" classification applies to the operation~~.

Example 1c: A lack of target information~~, e.g. when~~ does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first~~, does~~ would not ~~by~~in and of itself ~~constitute~~be a Misoperation.

~~**(2) A failure of a Protection System to operate for a non-Fault condition for which**~~In analyzing the Protection System ~~**was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the overall performance of the Protection System for the Element it is designed to protect is correct.**~~

~~A failure of a generator's composite Protection System to operate for a loss of field condition is an example of a "failure to trip"~~ for Misoperation~~. This type of Misoperation may require manual operator intervention.~~

~~A failure of a "primary" reverse power relay (or any other component) is not a "failure to trip" Misoperation as long as another component of the generator's composite Protection System operated to shut down the generator. Please see~~, the entity must also consider whether the "Slow Trip – During Fault" category ~~4 to see if the "slow trip" classification~~ applies to the operation.

~~The non-~~

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

~~**(3) A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. Delayed Fault clearing associated with an installed high-speed protection scheme is not a Misoperation if the high-speed performance has not been identified to meet the dynamic stability performance requirements of the TPL standards nor is it required to ensure coordination with other Protection Systems.**~~

~~A failure of a line's composite Protection System to operate as quickly as intended for a line Fault is an example of a "slow trip"~~ **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as another component of the generator's Composite Protection System operated as intended (e.g., isolating the generator).

In analyzing the Protection System for Misoperation~~. –~~, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This ~~type~~category of Misoperation typically results in remote backup Protection System operation~~s~~ before the Fault is cleared.

> ~~In many cases,~~**Example 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line Fault is a Misoperation.

Installing high-speed protection ~~is installed as~~ may be a part of ~~the~~a utility's standard practice without having the need for high-speed protection ~~for meeting TPL requirements. A slow trip of this Protection System~~to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic ~~performance of the BES; so, it does not need to be reported. However, even if high-speed clearing is not required, the~~BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems ~~must coordinate to prevent an "unnecessary trip" Misoperation (e.g. an over trip).~~.

The phrase "slower than ~~intended~~required" means the Composite Protection System operated slower than the objective of the owner(s). It would be ~~impossible~~impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should ~~have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide~~understand whether the speed ~~or~~and outcome of its Protection System operation ~~was adequate~~met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

The ~~reference to the TPL standards is meant to place some bounds on the time to clear a Fault and prevent dynamic instability. The performance requirements~~phrase "resulted in the ~~TPL standards are found in Table 1, and are applicable to all contingencies mentioned for Type A, B and C contingencies.~~

~~Coordination with~~operation of any other Composite Protection System~~s~~" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e~~.~~., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

~~**(4) A Protection System operation that is slower than intended for a non-Fault condition such as a power swing, under-voltage, over excitation, or loss of excitation for which it was intended to operate.**~~

~~A failure of a generator's composite Protection System to operate as quickly as intended for an over excitation condition is an example of a "slow trip" Misoperation. This type of Misoperation may result in equipment damage.~~

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

Slow Trip – Other Than Fault

The phrase "slower than ~~intended~~required" means the ~~c~~Composite Protection System operated slower than the objective of the owner(s). It would be ~~impossible~~impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should ~~have an understanding of the objectives of its Protection Systems, whether those systems operated fast enough to prevent additional harm, and ultimately be able to decide~~understand whether the speed ~~or~~and outcome of its Protection System ~~was adequate~~operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation. This category of Misoperation could result in equipment damage.

The ~~non-~~"Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

~~**(5) A Protection System operation for a Fault for which the Protection System is not intended to operate.**~~

~~An operation of a transformer's composite Protection System which over trips for a properly cleared line Fault is an example of an "unnecessary trip" Misoperation. For this type of Misoperation, the Fault is typically cleared properly by the faulted equipment's composite Protection System (line relaying, in this case) without the need for an external Protection System's operation.~~

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System~~s~~ is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the ~~local~~Composite Protection System of the Faulted Element to clear the Fault. ~~An~~A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

~~**(6) A Protection System operation for a non-Fault condition for which the Protection System is not intended to operate, and is unrelated to on-site maintenance, testing, inspection, construction or commissioning activities.**~~

> ~~Non-Fault~~ **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to, power swings, ~~over excitation~~overexcitation, loss of excitation, frequency excursions, and normal ~~condi~~operations.

> **Example 6a:** An operation of a line's ~~c~~Composite Protection System due to a relay failure during normal ~~conditions is an example of an "unnecessary trip other than Fault"~~operation is a Misoperation.
>
> ~~In a second example, tripping~~**Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation~~. In a third example, an~~ assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because ~~it was set with an excessive reach that unnecessarily restricted the line's load carrying capability~~power swing blocking was enabled and should have prevented the trip, but did not.

~~An~~Additionally, an operation that occurs during a non-~~f~~Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.~~ However~~

> **Example 6d:** A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation.

The "on-site" activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning ~~has been completed~~is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of ~~the technical~~on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements, are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. ~~This definition is based on the established IEEE/PSRC I3 Working Group on 'Transmission Protective Relay System~~

~~Performance Measuring Methodology' categories (excluding Failure to Reclose) of Relay System Misoperation. The phrase abnormal condition has been replaced with "non-fault condition" to remove ambiguity.~~

~~The exclusion of a component failure, as long as the composite Protection System operates correctly, was based on recommendations by the NERC SPCS. Entities still need to review each Protection System operation. Covering these types of component failures within the standard constitutes additional administrative burden for types of failures that have no immediate reliability impacts.~~

~~Failure to automatically reclose after a Fault is not included as a Misoperation because reclosing equipment is not included under the definition of Protection Systems.~~

> In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

The above are examples only, and do not constitute an all-inclusive list of conditions that would not be a Misoperation.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, ~~Static VAR Compensators (SVCs), Flexible AC Transmission Systems~~static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), ~~High-Voltage DC (HVDC~~high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. ~~Additionally, operations initiated by control functions within protective relays are not considered Protection System operations. For example, in cases where a component of the Protection System or a function of a component within the Protection System is used for control of a generator, such as when a reverse power relay is used to trip a breaker during generator shutdown, the operation of the control component or the function when not providing protection is not included in the definition of Misoperation and its operation would not be reviewed under this standard. Automation (e.g. data collection) is also not a protective function and is not subject to this standard~~ The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

~~A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation provided no in-service BES Elements are tripped. These types of operations are excluded when the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements are not Misoperations. Protection System operations unrelated to on-site maintenance, testing, inspection, construction or commissioning activities which occur with the protected Element out of service, that trip any in-service Elements are Misoperations.~~

~~In some cases where zones of protection overlap, the owner of BES Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System~~

~~performance for an Element. For example, the high side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high side of the connected transformer. Therefore, the operation of the line relaying for a high side transformer Fault would not be considered a Misoperation.~~

> ~~This standard addresses the reliability issues identified in the letter[5] from Gerry Cauley, NERC President and CEO, dated January 7, 2011. "Nearly all major system failures include misoperation of relays as a factor contributing to the propagation of the events…….. Reducing the risk to reliability from relay Misoperations requires consistent collection of misoperation information by regional entities, along with systematic analysis and correction of the underlying causes of preventable Misoperations." The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[6]; July 2011 "….a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."~~

Control Functions

The entity must make a determination as to whether the standard is applicable to its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit.

~~[5] http://www.nerc.com/news_pr.php?npr=723~~[5] ~~http://www.nerc.com/pa/Stand/Project%202010005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf~~

~~[6] http://www.nerc.com/files/2011_RARPR_FINAL.pdf~~

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster~~, note that the~~ or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation ~~effective January 15, 2008 provides that the Compliance Monitor~~, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

~~**Requirement R1**~~

~~This requirement promotes the prudent evaluation of each Protection System operation to determine if the operation was correct or a Misoperation, even those Misoperations difficult to detect. Unless all BES Protection System operations and Faults that challenge them are reviewed, it cannot be determined with certainty that all Misoperations are identified. For example, if you only reviewed operations resulting in an overtrip, you would not necessarily identify Misoperations caused by slow trips.~~

~~Requirement R1 places the responsibility on~~ The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement R1

This requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner ~~to investigate~~ typically monitors and tracks device operations ~~initiated by a Protection System. The drafting team believes,~~ the owner is the logical starting point for identifying Misoperations of ~~the~~Protection Systems for BES ~~interrupting device that operated would be in the best position to analyze the Protection System operation, determine if a Misoperation occurred, and perform the initial investigation to determine the cause of the Misoperation. If the~~ Elements. A review is required when (1) a BES interrupting device ~~owner does not own all of the~~ operates that is caused by a Protection System ~~and cannot determine that the~~or by manual intervention in response to a Protection System ~~operation was correct, then notify~~failure to operate, (2) regardless of whether the ~~other~~ owner~~(s)~~ owns all or part of the Protection System component(s), and (3) the owner identified that its Protection System component(s) ~~and provide~~as causing the BES interrupting device operation.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any ~~requested investigative information. In this case, it is expected that both entities will work together to investigate the cause of the operation~~Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

Protection Systems are made of many components. These components may be owned by ~~more than one entity.~~different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing ~~any~~ information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken~~. If an entity feels it cannot get the level of cooperation it needs to adequately address a Misoperation, the entity should appeal to its Regional Entity for help in resolving the situation~~.

~~Determining~~Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Requirement R2

For Requirement R2 (i.e., case of multi-entity ownership), the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) when the criteria in Requirement R2 is met.

This requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking or DCB relaying on 03/03/2014 at 15:43 UTC during an external fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the latter half of the 120 calendar days allotted to the BES interrupting device owner.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, the entity is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, or requesting a necessary outage.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause.

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: All relays at station A and B functioned properly during testing on 08/26/2014. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

> **Example R4c:** The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations ~~is essential in developing an effective remedy to avoid future Misoperations. The drafting team recognizes that~~benefits BES reliability by preventing recurrence. The Corrective Action Plan or CAP is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must create the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation; in these circumstances, the CAP would include a remedy for the identified causes. The ~~60 day clock for developing the CAP will be associated with the determination of the first cause. A CAP can~~CAP may be revised if additional causes are found~~. The drafting team believes 120 calendar days is a reasonable period of time to investigate operations, determine the cause for most Misoperations and document findings in a Misoperation investigation report. This time frame takes into account the seasonal nature of Protection System operations. Both the volume of Protection System operations as well as outage constraints for investigative purposes can be seasonal.~~

~~Regardless of whether a cause is identified, the BES interrupting device owner must document the investigation as a potential aid in possible future Misoperation investigations. If a~~ ; therefore, the entity has the option to create a single ~~Protection System causes~~or multiple ~~BES interrupting device owners to be affected, the entities may work together to produce a common Misoperation investigation report. Similarly, if the BES interrupting device owner and the Protection System component owner that caused a Misoperation are different entities, they may work together to produce a common report.~~

~~A Misoperation investigation report or documented findings may include the following information: 1) initial evidence, 2) probable causes, 3) tests and studies, and 4) conclusions. A brief description of the event surrounding the Misoperation may be included if not separately documented. The initial evidence, which may also be documented separately, contains the sequence of events, relay targets and a summary of Disturbance Monitoring Equipment (DME) records as appropriate. Probable causes are those causes which are most likely to have contributed to the Misoperation and could be considered for further testing. The test and studies documented in the report would describe and provide findings of those tests if the entity was able to perform them during the initial investigation phase (e.g. relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests) and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the cause. The conclusions should summarize the cause(s) substantiated by the evidence and findings of the tests and studies.~~

~~Requirement R2~~

~~If the Misoperation cause is identified within 120 days of the event, Requirement R2 requires Protection System owners to develop a CAP or to make a declaration of no additional action within 60 calendar days of determining the cause. The drafting team recognizes there may be~~ CAPs to correct multiple causes ~~for~~of a Misoperation~~; in these circumstances the CAP would include a remedy for the identified causes~~. The 60 calendar day ~~clock~~period for developing ~~the CAP will be associated with the determination of the first cause. A~~ a CAP ~~can be revised if additional causes are found. Based on~~ (or declaration) is established on the basis of industry experience ~~and~~ which includes operational coordination timeframes, ~~the drafting team believes 60 calendar days is reasonable for considering such things as~~time to consider alternative solutions, coordination of resources, ~~or~~and development of a schedule ~~for a CAP, or to prepare a declaration justifying the lack of a CAP~~.

~~The 120 day time period and the 60 day~~The time periods within Requirement R1, R3 and Requirement R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period ~~are distinct and within the context of~~in Requirement R1 ~~and Requirement R2 respectively, need~~or R3 ends and the 60 calendar day period to ~~remain separate. With~~develop the CAP becomes applicable. The ultimate goal ~~of keeping the implementation~~is to keep all time ~~of a CAP~~periods as short as possible, ~~if a cause of a Misoperation is determined quickly the CAP creation timeframe (60 days) becomes applicable and requires the CAP implementation be less than 180 days. Also, if the interrupting device owner is tardy in informing another Protection System component owner and using up much of the 120 day period, it still leaves a considerable amount of time (at least 60 days) to develop an action plan for further investigation by the Protection System component owner, or if a cause is determined the creation of the CAP.~~

including the correction of the cause(s) of the Misoperation. Where there are multiple Protection System owners involved in a Misoperation, ~~the one or more owners~~ each owner whose Protection System component(s) contributed to the Misoperation ~~will create a CAP or declaration as required by Requirement R2. Owners whose Protection System components operated correctly do not need to create a CAP~~is subject to Requirement R5.

~~Resolving Misoperations benefits the Protection System owner and the BES by maintaining reliability and security. The CAP is an established tool for resolving operational problems. The NERC Glossary of Terms defines a Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem".~~

~~Protection System owners are expected to exercise due diligence in the~~The development ~~and implementation~~ of a CAP~~. Typically included would be any~~ is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence ~~(along with~~, the ~~date performed), any corrective~~timetable for executing such actions ~~planned to be taken to prevent recurrence (along with the planned date),~~, and an evaluation of the CAP's applicability to the entity's other Protection Systems ~~owned by the entity.~~

including other locations. The evaluation of ~~the CAP's applicability to~~ these other Protection Systems ~~owned by~~aims to reduce the ~~entity is intended to encourage diligence in preventing~~risk and likelihood of similar Misoperations~~.~~ in other Protection Systems. The Protection System owner is responsible for determining the ~~scope of the problem, and for including appropriate actions in the CAP.~~ extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in ~~adding preemptive actions to the CAP. The CAP is complete when~~

~~all specified actions are completed~~the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP must include an evaluation of other Protection Systems including other locations to be complete.

The following ~~are examples~~is an example of ~~Corrective Action Plans (CAPs):~~

a CAP ~~Example 1 – Corrective actions~~ for a ~~failed~~ relay ~~only:~~

~~The impedance relay was removed from service on 6/2/12 because it~~Misoperation that was applying a standing trip~~. Relay testing was performed on 6/4/12. A~~ due to a failed capacitor ~~was found within the impedance relay. The~~ and the evaluation of the cause at similar locations which determined capacitor ~~was replaced on 6/5/12. The impedance relay functioned properly during testing after the~~replacement was not necessary.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor~~ was replaced. The impedance~~. Test the relay~~ was returned~~. Return to service ~~on 6/5/12~~or replace by 07/01/2014.
>
> Applicability to other Protection Systems: ~~Undesired trips of this~~ This type of impedance relay ~~due to capacitor failures have occurred only occasionally within our system. This type of impedance relay is gradually~~has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized.~~ It is therefore our assessment~~ Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for ~~our~~the system.

~~CAP Example 2 - Corrective actions for a failed relay, and a program for preemptive actions at similar installations:~~

~~The impedance~~The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay ~~was removed~~ from service~~ on 6/2/12 because it was applying a standing trip. Relay testing was performed on 6/4/12. A failed capacitor was found within the impedance relay. The~~. Replace capacitor~~ was replaced on 6/5/12. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned~~. Test the relay. Return to service ~~on 6/5/12~~or replace by 07/01/2014.
>
> Applicability to other Protection Systems: ~~Undesired trips of this~~This type of impedance relay ~~due~~is suspected to~~ capacitor failures~~ have ~~occurred frequently. It is therefore our assessment that~~ previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/~~1/12~~01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer Fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following in an example of a declaration made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase fault. The protection scheme utilized for both protection groups is a POTT. The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. The failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. The failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/~~12~~2014.

CAP ~~Example 3 – Corrective~~completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay; and preemptive actions for similar installations~~:~~ (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on ~~6/2/12~~06/02/2014 because it was applying a standing trip. ~~Relay testing was performed on 6/4/12. A~~The failed capacitor was found within the impedance relay~~. The capacitor was~~ and replaced~~on 6/5/12.~~. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on ~~6/5/12~~06/05/2014.

~~Applicability to other Protection Systems: Undesired trips of this type of~~The impedance relay ~~due to~~ capacitor ~~failures have occurred frequently. It is therefore our assessment that preemptive~~ replacement ~~of capacitors in this type of impedance relay should be pursued.~~

~~It is planned to replace the impedance relay capacitors~~was completed at stations A, B, and C ~~by 9/1/12. It is planned to replace the~~on 08/16/2014. The impedance relay ~~capacitors~~capacitor replacement was completed at stations D, E, and F ~~by 11/1/12. It is planned to replace the~~on 10/24/2014. The impedance relay ~~capacitors at~~capacitor replacement for stations G, H, and I ~~by 2/1/13.~~

~~The impedance relay~~were postponed due resource rescheduling from 02/01/15 to 03/01/2015. Following the timetable change, capacitor replacement was completed ~~at stations A, B, and C on 8/16/12. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/26/12. The impedance relay capacitor replacement was completed at stations~~ on 03/09/2015 at stations G, H, and I~~on 1/9/13~~. All stations identified in the evaluation have been completed.

CAP ~~Example 4 – Corrective~~completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem; and preemptive actions for similar installations~~:~~. (See also, Example R5d).

Example R6d: Actions: Fault records were provided to the manufacturer on ~~6/4/12. On 6/11/12, the~~06/04/2014. The manufacturer responded that the ~~m~~Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on ~~6~~08/12/~~12~~2014.

~~Applicability~~Nine of the twelve relays were updated to ~~other Protection Systems: Based on our risk assessment, we plan to install firmware~~ version 3 ~~at all of our installations that are~~ firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2~~. Proposed completion date is 12/31/12.~~

~~The~~ firmware ~~replacements were~~ were updated to version 3.01 firmware on 11/10/2014.

CAP completed on ~~12/4/12~~11/10/2014.

~~If~~The CAP is complete when all the documented actions to resolve the specific problem (i.e., Misoperation ~~cause is identified within 120 days, and no corrective action has been or is intended to be taken, Protection System owners~~) are ~~required to make a declaration to this effect. A "no CAP declaration" would typically~~ completed which may include ~~the Misoperation cause and justification for taking no corrective action.~~

~~An example~~those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP.

Process Flow Chart: Below is a ~~"no CAP declaration" due to BES reliability might be: "The investigation showed the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Our studies show that de-sensitizing~~ graphical representation of the ~~relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations." A "no CAP declaration" due to BES reliability is~~ expected ~~to be used sparingly.~~

~~There are some cases where a Misoperation cause is outside of an entity's control and would result in a "no CAP declaration." Items that may be considered outside of an entity's control could be a non-registered entity communications provider problem or a transmission transformer tapped industrial customer who initiates a direct transfer trip to a registered entity's transmission breaker. Generally, situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control. The "outside an entity's control" declaration is expected to be used sparingly.~~

~~**Requirement R3**~~

~~If the Misoperation cause is not identified within 120 days, and reasonable investigative actions have not been exhausted, Protection System owners are expected to exercise due diligence in the development and implementation of an action plan for additional investigation. This action plan would typically include any investigative actions taken to determine the cause (along with the date performed), and any investigative actions planned to be taken to determine the cause (along with the planned date).~~

~~At the end of 180 days, the Protection System owner must have an action plan or a declaration why no further actions will be taken. The action plan does not need to have been implemented within the 180 days, but it must have been developed within this time frame. The 180 calendar days are the sum of 120 calendar days (investigative period in Requirement R1) and a 60 calendar day period (similar timeframe as in Requirement R2 for developing a CAP.)~~

~~Where there are multiple Protection System owners involved in a Misoperation and no cause has been determined, then each Protection System owner must either develop an action plan or declare why no further actions will be taken.~~

~~An example of an investigative action plan for more testing might be: "All relays at station A functioned properly during testing on xx/xx/xx. An outage is required to test the relays at station B. The outage is scheduled for xx/xx/xx."~~

~~An example of an action plan for adding monitoring might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. It is planned to install a temporary DFR at station A on xx/xx/xx and to monitor the currents for at least 3 months."~~

~~An example of an action plan for reviewing relay settings might be: "All relays at station A functioned properly during testing on xx/xx/xx. All relays at station B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. It is planned to complete a relay settings review~~ process created by ~~xx/xx/xx."~~

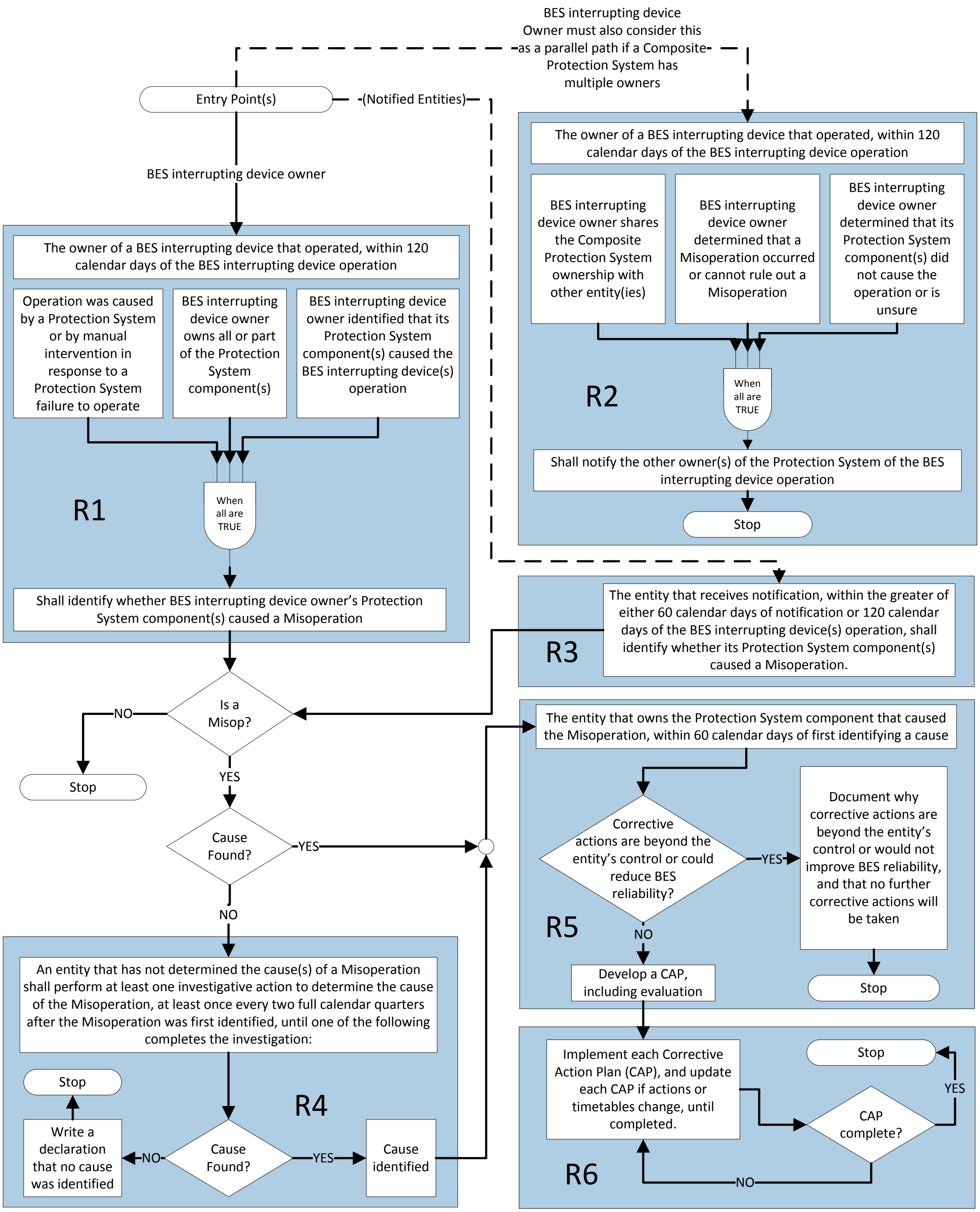
~~If the Misoperation cause is not identified and reasonable investigative actions have been exhausted within 180 days, Protection System owners are required to make a declaration to this~~

~~effect. A "no action plan" declaration would typically include any investigative actions taken to determine the cause (along with the date performed), and justification for taking no additional investigative actions.~~

~~An example of a "no action plan" declaration might be: "All relays at station A and B functioned properly during testing on xx/xx/xx. The carrier system functioned properly during testing on xx/xx/xx. The carrier coupling equipment functioned properly during testing on xx/xx/xx. A settings review completed on xx/xx/xx indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be proper, and the equipment at station A and station B is already monitored, we have decided to close this investigation."~~

~~Requirement R4~~

~~The goal of~~ the standard ~~has not been met unless CAPs or action plans are actually implemented, as is required in Requirement R4. The responsible entity is required to implement and complete a CAP or action plan to accomplish the purpose of this standard, which is to prevent future Misoperations, thereby minimizing risk to the BES. The responsible entity is also required to complete the CAP or action plan, document the plan implementation, and retain the appropriate evidence to demonstrate implementation and completion.~~, including the relationships between requirements:



~~The goal of an action plan created in Requirement R3 is to determine a cause so a CAP can be created to ultimately remedy the cause of the Misoperation. If the cause is determined as a result of the action plan, the entity must develop a CAP or a declaration within 60 days of determination of cause per Requirement R2. This requirement sets the expectation that the work identified in the CAP or action plan will be completed on schedule as planned. Deferrals or~~

~~other relevant changes to the CAP or action plan need to be documented so that the record includes not only what was planned, but what was implemented. Depending on the planning and documentation format used by the responsible entity, evidence of successful CAP or action plan execution could consist of signed-off work orders, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, paid invoices, photographs, walk-through reports or other evidence.~~

~~Documentation of a CAP or action plan provides an auditable progress and completion confirmation for specific Misoperations. In addition, the investigative documentation may aid the responsible entity in remedying future Misoperations of a similar nature.~~

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage,

overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition for which it is designed. Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation that is caused by on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

Except in the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months 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. Except in the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

In the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months 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. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-004-3, All Requirements

Each Transmission Owner, Generator Owner, and Distribution Provider applicable to this standard shall be 100% compliant upon the effective date of the standard.

The extended implementation for the Western Interconnection is provided to allow an opportunity to make the necessary changes to the PRC-004-WECC-1 Regional Reliability Standard. An overlap in performance between the regional and proposed continent-wide standard was identified during the development of the proposed PRC-004-3 Reliability Standard.

Implementation Plan for definitions

The revised definition of Misoperation and the new definition of Composite Protection System shall be implemented concurrently with the standard upon the effective dates noted above. Note that the Western Interconnection has an extended implementation.

Retirement of Existing Standards

Except in the Western Interconnection, the existing standards PRC-003-1 and PRC-004-2.1a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3. In the Western Interconnection, the existing standards PRC-003-1 and PRC-004-2.1a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3 for the Western Interconnection.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard~~s~~ drafting team proposes ~~modifying~~ the following ~~approved~~new definition:

Composite Protection System:

> The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

> The failure of ~~an Element's composite~~a Composite Protection System to operate as intended. Any of the following is ~~considered~~ a Misoperation:
>
> 1. **Failure to Trip ~~-~~– During Fault ~~-~~–** A failure of a Composite Protection System to operate for a Fault ~~within the zone~~ condition for which it is designed~~ to protect~~. The failure of a Protection System component is not a Misoperation as long as the ~~overall~~ performance of the Composite Protection System ~~for the Element it is designed to protect~~ is correct.
> 2. **Failure to Trip ~~-~~– Other Than Fault ~~-~~–** A failure of a Composite Protection System to operate for a non-Fault condition for which ~~the Protection System was intended to operate~~it is

designed, such as a power swing, ~~under-voltage, over excitation~~undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the ~~overall~~ performance of the Composite Protection System ~~for the Element it is designed to protect~~ is correct.

3. **Slow Trip ~~-~~– During Fault ~~-~~–** A Composite Protection System operation that is slower than ~~intended~~required for a Fault ~~within the zone~~ condition for which it is designed ~~to protect~~. Delayed ~~Fault~~ clearing ~~associated with an installed high-speed protection scheme is not~~ of a Fault condition is a Misoperation if ~~the~~ high-speed performance ~~has not been~~was previously identified ~~to meet the~~ as being necessary to prevent voltage or dynamic ~~stability performance requirements of the TPL standards nor is it required to ensure coordination with~~instability, or resulted in the operation of any other Composite Protection System~~s~~.

4. **Slow Trip ~~-~~– Other Than Fault ~~-~~–** A Composite Protection System operation that is slower than ~~intended~~required for a non-Fault condition for which it is designed, such as a power swing, ~~under-voltage, over excitation~~undervoltage, overexcitation, or loss of excitation ~~for which the Protection System was intended to operate~~. Delayed clearing of a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.

5. **Unnecessary Trip ~~-~~– During Fault** ~~- A~~– An unnecessary Protection System operation for a Fault ~~for which the Protection System is not intended to operate~~condition on another Element.

6. **Unnecessary Trip ~~-~~– Other Than Fault** ~~-~~– An unnecessary Protection System operation for a non-Fault condition for which it is not designed. A Protection System operation ~~for a non-Fault condition for which the Protection System is not intended to operate, and~~ that is ~~unrelated to~~caused by on-site maintenance, testing, inspection, construction or commissioning activities~~.~~

~~**Background**~~

~~PRC-004-3 Protection System Misoperation Identification and Correction~~ is ~~a revision of PRC-004-2a Analysis and Mitigation of Transmission and Generation Protection System Misoperations with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated. PRC-003-1 Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems required the Regions to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a fill-in-the-blank standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional procedures to support the requirements of PRC-004-2a. This is~~ not a ~~potential~~

~~reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2a~~Misoperation.

General Considerations

~~PRC-004-WECC-1 – This regional standard is related to reporting of Misoperations for a limited set of WECC Paths and Remedial Action Schemes. In those cases where PRC-004-WECC-1 overlaps with the Continent-wide standard, entities are expected to comply with the more stringent standard.~~

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements.
- ~~Underfrequency Load Shedding (UFLS) that trips a BES Element~~
- ~~Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded~~
- Non-protective functions that ~~may be imbedded~~are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

~~First day of~~Except in the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twelve months ~~beyond~~after the date that ~~PRC-004-3~~the standard is approved by an applicable ~~regulatory authorities, or in those jurisdictions~~governmental authority or as otherwise provided for in a jurisdiction where ~~regulatory~~ approval by an applicable governmental authority is required for a standard to go into effect. Except in the Western Interconnection, where approval by an applicable governmental authority is not required, the standard ~~becomes~~and definitions shall become effective on the first day of the first calendar quarter that is twelve months ~~beyond~~after the date ~~this~~the standard is ~~approved~~adopted by the NERC Board of Trustees~~,~~ or as otherwise ~~made effective pursuant to the laws applicable to such ERO governmental authorities~~provided for in that jurisdiction.

~~The proposed definition of Misoperation~~ In the Western Interconnection, the standard and definitions shall become effective on the ~~same date as PRC-004-3. Entities shall use this definition when implementing any portions of Requirements R1, R2 R3 and R4 that use this defined term.~~

~~Implementation Plan for~~ Requirements R1, R2, R3 and R4

~~Entities shall be 100% compliant for any new Protection System Operation on the~~ first day of the first calendar quarter ~~twelve~~that is twenty-four months ~~following~~after the date that the standard is approved by an applicable ~~regulatory approvals,~~governmental authority or as otherwise provided for in ~~those jurisdictions~~a jurisdiction where ~~no regulatory~~ approval by an applicable governmental authority is required~~,~~ for a standard to go into effect. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter ~~twelve~~that is twenty-four months ~~following~~after the date the standard is adopted by the NERC Board of Trustees ~~adoption. Protection System operations that occur before the compliance date shall comply with the previous version of the Standard~~or as otherwise provided for in that jurisdiction.

Implementation Plan for PRC-004-3, All Requirements

Each Transmission Owner, Generator Owner, and Distribution Provider applicable to this standard shall be 100% compliant upon the effective date of the standard.

The extended implementation for the Western Interconnection is provided to allow an opportunity to make the necessary changes to the PRC-004-WECC-1 Regional Reliability Standard. An overlap in performance between the regional and proposed continent-wide standard was identified during the development of the proposed PRC-004-3 Reliability Standard.

Implementation Plan for definitions

The revised definition of Misoperation and the new definition of Composite Protection System shall be implemented concurrently with the standard upon the effective dates noted above. Note that the Western Interconnection has an extended implementation.

Retirement of Existing Standards

~~The~~ Except in the Western Interconnection, the existing standards PRC-003-1 and PRC-004-~~2a~~2.1a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3. In the Western Interconnection, the existing standards PRC-003-1 and PRC-004-2.1a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3 for the Western Interconnection.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-05.1 Protection System Misoperations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the PRC-004-3 Standard. The comment form must be completed by **March 3, 2014**.

If you have questions please contact Scott Barfield-McGinnis or by telephone at 404-446-9689.

http://www.nerc.com/pa/Stand/Pages/Project2010-05_Protection_System_Misoperations.aspx

Background Information

This posting is soliciting formal comment.

The third draft of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 with a successive ballot in the last ten days of the comment period. Stakeholders from approximately 132 companies representing all ten Industry Segments provided feedback. The Protection System Misoperation Standard Drafting Team (PSMSDT) has responded to all commenters and developed a fourth draft of the standard for Protection System Misoperation Identification and Correction based on stakeholder input. Changes to the standard include:

Summary of Changes

The PSMSDT made substantive revisions to the previous draft 3 of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard following its previous 30-day formal comment posting of the standard and successive ballot which received 50.60% stakeholder approval. The following narrative is a summary of the substantive revisions made to the proposed draft 4 of the PRC-004-3 standard.

Definitions

Composite Protection System: The SDT is proposing a new definition to support the revisions to the definition of Misoperation.

Misoperation: The SDT made updated occurrences of “composite Protection System” with the newly proposed term of Composite Protection System. Other revisions include removing the uses of “zone,” and most notably updated the category of “Slow Trip – During Fault” to address high-speed performance. The last category of “Unnecessary Trip – Other Than Fault” was modified to be clear that a Protection System operation due to on-site personnel is not a Misoperation.

Purpose

The purpose statement was reorganized to clarify that the standard applies to those Protection Systems for Bulk Electric System Elements

Facilities

The SDT revised the Facilities section of the Applicability to remove exclusions for Special Protection Systems (SPS) and Remedial Action Schemes (RAS). As a general rule, Reliability Standards should address what is applicable, not what is excluded; therefore, SPS and RAS are not referenced in the Applicability. Exclusions concerning non-protective functions embedded within a Protection System and protective functions intended to operate as a control function (e.g., reverse power when removing a generator from service) have been moved to the main Applicability for Facilities to add clarity that these are not applicable as Protection Systems for Bulk Electric System (BES) Elements.

Effective Dates

The effective dates have not materially changed even though the language shows significant modification. This language change is being applied to Reliability Standards that are currently under development. The change is an outcome of NERC working with Canadian authorities to address their specific circumstances. Also, the Effective Date language now incorporates a provision for the Western Interconnection due to identified overlap between the Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation and the proposed continent-wide Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction. The provision is to allot time for the Western Interconnection to modify the Regional Reliability Standard.

Requirement R1

The SDT reorganized Requirement R1 to improve clarity of the required performance, allotted time periods, and a single reliability objective in a Requirement. The main part of the Requirement begins with defining what starts the review of a Misoperation, which is the operation of a BES interrupting device. In replacing the earlier Part 1.1 and its sub-bullets, the responsible entity will perform a review when the criteria (i.e., 1.1, 1.2, and 1.3) are met. The three criteria include when: the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; the BES interrupting device owner owns all or part of the Protection System component(s); and the BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. Part 1.2 is now represented in Requirement R4 to investigate the identified Misoperation to determine a cause, if not previously revealed during the initial review of a Misoperation.

There were a significant number of comments from stakeholders about the confusion between the proposed “action plan” and the “Corrective Action Plan” found in previous Requirement R3. To address these comments, the SDT created Requirement R4 to allow an entity to continue its investigation, as needed, only requiring the entity to demonstrate actions taken at least once in every two calendar quarters toward determining the cause of an identified Misoperation.

Requirement R2

This requirement is essentially unchanged and is now represented in Requirement R5, the development of a Corrective Action Plan (CAP) to address the cause(s) of an identified Misoperation. The SDT made clarifying revisions to pinpoint the Protection System component that caused the Misoperation as being subject to the (CAP). Also, the word “first” was added before “…identifying the cause…” to improve clarity that upon identifying the “first cause” starts the 60 calendar day time period for developing the CAP. Last, the SDT added the clause “…and that no further corrective actions will be taken” to require entities to clearly state that no additional actions are planned to be taken to provide a measurable close to the performance in the declaration. Also, the phrase “would reduce BES reliability” was replaced with “would not improve BES reliability” to align with those conditions where corrective action may not be practical.

Requirement R3

This requirement was removed by the SDT in the current draft as comments revealed the use of “action plan” along with Corrective Action Plan created unnecessary confusion. The proposed Requirement R4 fills this performance by requiring entities to continue its investigative actions in determining a cause of an identified Misoperation.

Requirement R4

This requirement is now Requirement R6 and is essentially the same as the previous Requirement R4, except that “action plan” was removed. Implementation is further clarified that the CAP must be updated when actions or timetables change through completion of the CAP.”

Compliance

The SDT corrected this section to comport with the standard language NERC uses in Reliability Standards. Also, the Evidence Retention section was changed to reduce the minimum time periods that were previously proposed at six years (i.e., the last audit) for all Requirements to 12 calendar months for all Requirements according to the Standard Drafting Guidelines for evidence retention.

VRFs and VSLs

After further review, the SDT lowered the earlier Requirement R4 (implement the CAP) Violation Risk Level (VRF) from High to Medium. This comports with the VRF found in PRC-016-0.1 – Special Protection System Misoperation, Requirement R2 and PRC-022-1 - Under-Voltage Load Shedding Program Performance, Requirement R1.2. See the VRF and VSL Justifications document for additional information.

The Violation Severity Levels were completely rewritten due to the substantive changes made in restructuring the Requirements to meet a single reliability objective in a requirement. The SDT notes that it applied the VSL Guidelines in establishing the VSLs including the incremental differences between each level.

Application Guidelines

The SDT substantially reorganized the Guidelines and Technical Basis section of the Application Guidelines for organization and flow. Section headers were added and reordered as well as creating additional examples for guidance. For instance, the examples for Requirement R5 and R6 mirror one another to demonstrate an example of Corrective Action Plan (CAP) development (R5) and its implementation (R6).

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. Based on stakeholder input, the drafting team created a new definition for **Composite Protection System** to support the definition of **Misoperation**. The Slow Trip categories of Misoperation were also clarified. Do you agree with the new and revised definitions? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

2. Based on stakeholder input, the drafting team modified the previous Requirement R1 to clarify responsibilities where two or more entities share ownership of a Protection System. The proposed Requirement R2 determines when other entities are notified and Requirement R3 now clarifies that the notified entity has the greater of 60 calendar days from notification or 120 calendar days from the BES interrupting device operation. Do you agree this modification clarified the performance for notification (R2) and the notified (R3)? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

3. Based on stakeholder input, the drafting team removed the previous Requirement R3 (action plan) and proposed a new Requirement R4 which provides entities time to investigate the Misoperation to determine its cause(s). Do you agree this modification clarified performance and removed ambiguity regarding the action plan? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

4. The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

5. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

   Comments:

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions to the standard, those changes are identified in the "Proposed Replacement" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also direct focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners of the Composite Protection System when it determines (or is unsure) its Protection System components did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to continue its investigative work to determine the cause(s) of an identified Misoperation until the cause is determined or

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		the entity concludes that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**4.2.** **Facilities:** **4.2.1** Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded. **4.2.2** Underfrequency load shedding	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for BES Elements. Additional language is provided for clarity that non-protective functions are not applicable and

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	(UFLS) that is intended to trip one or more BES Elements.	those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service). The Applicability is further clarified to include underfrequency load shedding (UFLS) to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are addressed in phase two of this project.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for ensuring that other owners had a responsibility to be involved in the review and analysis.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.	
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: **2.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and	Requirement R2 now asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and a Misoperation occurred (or cannot be ruled out) in accordance with criteria 2.1 through 2.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.3** The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.	
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component owners during its review with the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		the rare case where the notifying entity takes the majority of its allotted time (120 days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause of a Misoperation. In most cases, the cause of a Misoperation will be revealed during the course of review and when a cause is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two calendar quarters until the entity determines the cause or declares that it has taken reasonable action and could not determine the cause.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of applicable entities. As such, Regional reporting will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. Metrics will be shared with each Region. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may document this as well. In cases where the entity, in its judgment, determines that a CAP is not practical for improving BES reliability, the entity must explain in a declaration its conclusions why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1.4. Identification of the Regional Reliability	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Organization group responsible for the procedures and the process for approval of the procedures.		Misoperations of its Protection System without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard and revised definition of Misoperation provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity's (formerly Regional Reliability Organization or RRO) approval. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability	None.	The proposed PRC-004-3 implicitly requires each

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.		applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization or applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded. **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	The same applicable entities will transition to the new standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions are not applicable and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service). Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are addressed in phase two of this project.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. **R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns	The already approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3). The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and a Misoperation occurred (or cannot be ruled out) in accordance with criteria 2.1 through 2.3.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: **2.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.2** The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.3** The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.	Requirement R3 provides the necessary performance for the notified Protection System owner to review its component(s) for Misoperation. Last, Requirement R4 requires the applicable entity to conduct investigative actions until is determines the cause(s) or declares that it has been unable to determine the cause(s). Requirement R5 addresses the "develop" a Corrective Action Plan (CAP)" portion, and Requirement R6 addresses the "implement" portion of the CAP.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	None.	Since the NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations. NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Mapping Document

~~Mapping Document Showing Translation~~Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems~~,~~ and PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 ~~—~~ – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions to the standard, those changes are identified in the "Proposed Replacement" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
~~**Requirement in Approved Standard**~~**4. Applicability:** **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider~~**Translation to New Standard or Other Action**~~	~~**Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction Or Comment**~~The proposed standard properly assigns responsibility to the registered functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner,

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
		Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:	~~PRC-004-3~~ ~~Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization.~~ ~~PRC-004-3 replaces the RRO procedures.~~	The Requirements in the proposed PRC-004-3 standard by their results-based construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also direct focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners of the Composite Protection System when it determines (or is unsure) its Protection System components did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to continue its investigative work to determine the cause(s) of an identified Misoperation until the cause is determined or the entity concludes that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.~~4.1. Functional Entities:~~ ~~4.1.1 Transmission Owner~~ ~~4.1.2 Generator Owner~~ ~~4.1.3 Distribution Provider~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
R1. ~~Part~~ **1.** ~~1.~~ The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	~~PRC-004-3~~ ~~Applicability Section 4.2 Facilities.~~ **4.2. Facilities:** **4.2.1** Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded. **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	~~**4.2. Facilities**~~ ~~**4.2.**~~ The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for BES ~~Facilities~~ ~~**4.2.2** Underfrequency Load Shedding (UFLS) that trips a BES Element~~ ~~**4.2.3** Special Protection Systems (SPS), Remedial Action Schemes (RAS), and Undervoltage Load Shedding (UVLS) are excluded~~ ~~**4.2.4** Non-protective functions that may be imbedded within a Protection System are excluded~~ Elements. Additional language is provided for clarity that non-protective functions are not applicable and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service). The

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Applicability is further clarified to include underfrequency load shedding (UFLS) to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are addressed in phase two of this project.
(Continued) **R1.** ~~**Part**~~ **1.**~~**2.**~~ ~~Data reporting requirements (periodicity~~ The Protection Systems to be reviewed and ~~format)~~analyzed for Misoperations~~.~~ (due to their potential impact on BES reliability).	~~NERC Rules of Procedure, Section 1600 data request~~**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and	~~N/A~~The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the “owner” of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for ensuring that other owners had a responsibility to be involved in the review and analysis.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and ~~1.1~~1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.	
(Continued) **R1.** ~~**Part**~~ **1.**~~**3.**~~ ~~Process for review, analysis follow up,~~ The Protection Systems to be reviewed and ~~documentation of Corrective Action Plans~~analyzed for Misoperations~~.~~ (due to their potential impact on BES reliability).	~~PRC-004-3~~ ~~Requirement R1 Requirement R2~~ ~~Requirement R3 Requirement R4~~**R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: **2.1** The BES interrupting device owner shares the Composite Protection	~~**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ ~~**1.1** Within 120 calendar days of a~~Requirement R2 now asserts a responsibility on the initiating entity (i.e., BES interrupting device ~~operation in its Facility caused by~~ owner) to notify other owners of the Composite Protection System when the cause of a Protection System operation~~, identify and review each Protection System operation.~~ ~~• If the entity owns both~~ was not caused (or is undetermined) by the BES interrupting device ~~and the Protection System, determine if it was a~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
	System ownership with any other entity; and 2.2 The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and 2.3 The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.	~~correct operation or~~ owner and a Misoperation • ~~If the entity owns the BES interrupting device but does not own all of the Protection System and~~ occurred (or cannot ~~determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.~~ o ~~The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.~~ ~~1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.~~ ~~R2. Each Transmission Owner, Generator Owner, or~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
		~~Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation:~~ • ~~Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or~~ • ~~Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.~~ ~~R3. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause:~~ • ~~Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or~~ • ~~A declaration explaining why no further actions~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
		~~will~~ be ~~taken.~~ ~~R4. Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed~~ruled out) in accordance with criteria 2.1 through ~~completion.~~2.3.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component owners during its review with the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 days) to conduct its review.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause of a Misoperation. In most cases, the cause of a Misoperation will be revealed during the course of review and when a cause is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two calendar quarters until the entity determines the cause or declares that it has taken reasonable action and could not determine the cause.
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of applicable entities. As such, Regional reporting will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics;

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. Metrics will be shared with each Region. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
	entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	changes not improve BES reliability, the entity may document this as well. In cases where the entity, in its judgment, determines that a CAP is not practical for improving BES reliability, the entity must explain in a declaration its conclusions why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1. ~~Part 1.~~**4.** Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	~~PRC-004-3~~ ~~Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization.~~ ~~PRC-004-3 replaces the RRO procedures.~~None.	~~**4.1. Functional Entities:**~~ ~~**4.1.1** Transmission Owner~~ ~~**4.1.2** Generator Owner~~ ~~**4.1.3** Distribution Provider~~The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection System without regard to the Region or Regions in which

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
		it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard and revised definition of Misoperation provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity's (formerly Regional Reliability Organization or RRO) approval. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	~~PRC-004-3~~ 4. **Applicability** ~~Section~~ : **4.1. Functional Entities** ~~- assigns the~~ : 4.1.1 Transmission Owner~~,~~ 4.1.2 Generator Owner~~, and~~ 4.1.3 Distribution Provider ~~as the responsible entity(s) replacing the Regional Reliability Organization.~~ ~~PRC-004-3 replaces the RRO procedures.~~	~~PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow. The standards development process mandates the standards be reviewed once every five years.~~ ~~**4.1. Functional Entities:**~~ The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
		such procedures or processes by the previous Regional Reliability Organization or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.~~4.1.1 Transmission Owner~~ ~~4.1.2 Generator Owner~~ ~~4.1.3 Distribution Provider~~ ~~See **PRC-004-3**~~
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator	~~PRC-004-3~~ ~~Applicability Section 4.1 Functional Entities - assigns the Transmission Owner, Generator Owner, and Distribution Provider as the responsible entity(s) replacing the Regional Reliability Organization.~~ ~~PRC-004-3 replaces the RRO procedures.~~ None.	~~PRC-004-3 is a results-based standard that achieves the reliability objectives of PRC-003-1. The requirements in the standard define the process for the responsible entities to follow.~~ ~~**4.1. Functional Entities:**~~ ~~**4.1.1** Transmission Owner~~ ~~**4.1.2** Generator Owner~~ ~~**4.1.3** Distribution Provider~~

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
Owners within 30 calendar days of approval of those procedures.		~~See **PRC-004-3**~~The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization or applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-~~2a~~ ~~–~~2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
~~R1.~~ ~~The~~ **4. Applicability:** **4.1.** Transmission Owner ~~and any~~ **4.2.** Distribution Provider that owns a transmission Protection System ~~shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.~~ **4.3.** Generator Owner	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider ~~PRC-004-3~~ ~~Requirement R1~~ ~~Requirement R2 Requirement R3 Requirement R4~~**4.2 Facilities:** **4.2.1** Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded. **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	~~**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall:~~ ~~**1.1** Within 120 calendar days of a BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation.~~ ~~• If the entity owns both the BES interrupting device and the Protection System, determine if it was a correct operation or a Misoperation~~ ~~• If the entity owns the BES interrupting device but does not own all of the Protection System and cannot determine that the Protection System operation was correct, then notify the other owner(s) of the Protection System component(s) and provide any requested investigative information.~~ ~~o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a~~

Standard: PRC-004-~~2a~~ – 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
		~~Misoperation of their component.~~ ~~1.2 Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.~~ ~~R2. Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation:~~ • ~~Develop a Corrective Action Plan (CAP) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or~~ • ~~Explain in a declaration why corrective actions are beyond the entity's control or would reduce BES reliability.~~

Standard: PRC-004-~~2a -~~ 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
		~~**R3.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of the associated BES interrupting device operation, complete for each Misoperation without an identified cause:~~ • ~~Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or~~ • ~~A declaration explaining why no further actions will be taken.~~ ~~**R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion.~~The same applicable entities will transition to the new standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies

Standard: PRC-004-~~2a –~~2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
		to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions are not applicable and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service). Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are addressed in phase two of this project.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection	~~PRC-004-3 Requirement R1 Requirement R2 Requirement R3 Requirement R4~~**R1.** Each Transmission Owner,	~~**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall: Within 120 calendar days of a BES interrupting device operation in its Facility caused by a~~ The already

Standard: PRC-004-~~2a~~ – 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar	Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. **R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns	approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3). ~~1.1~~ The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation~~, identify and review each Protection System operation.~~ • ~~If the entity owns both the BES interrupting device and the Protection System, determine if it~~ was ~~a correct operation or a Misoperation~~

Standard: PRC-004-~~2a~~ – 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to ~~New Standard~~PRC-004-3 or Other Action**	**~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments**
nature according to the Regional Entity's procedures.	a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Protection System of the operation when: **2.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.2** The BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.3** The BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.	~~If the entity owns~~not caused (or is undetermined) by the BES interrupting device ~~but does not own all of the Protection System~~owner and a Misoperation occurred (or cannot ~~determine that the~~be ruled out) in accordance with criteria 2.1 through 2.3. Requirement R3 provides the necessary performance for the notified Protection System ~~operation was correct, then notify the other owner(s) of the Protection System~~ owner to review its component(s) ~~and provide any requested~~for Misoperation. Last, Requirement R4 requires the applicable entity to conduct investigative ~~information.~~actions until is determines the cause(s) or declares that it has been unable to determine the cause(s). ~~o The Protection System component owner(s) that was notified by the BES interrupting device owner shall determine if there was a correct operation or a Misoperation of their component.~~

Standard: PRC-004-~~2a – ~~2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
	R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the	~~**1.2** Within the same 120 day period of a BES interrupting device operation caused by a Protection System operation, the owner of the Protection System component identified as contributing to the Misoperation shall investigate and document the findings for each Misoperation including a cause, if identified.~~ ~~**R2.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 60 calendar days of identifying the cause of each Misoperation:~~ ~~Develop~~ • Requirement R5 addresses the "develop" a Corrective Action Plan (CAP~~) for the identified Protection System component(s) that includes an evaluation of the CAP's applicability to the entity's Protection Systems at other locations, or~~ • ~~Explain in a declaration why corrective actions are beyond the entity's control or would~~

Standard: PRC-004-~~2a~~ – 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
	investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve	~~reduce BES reliability.~~ ~~**R3.** Each Transmission Owner, Generator Owner, or Distribution Provider shall, within 180 calendar days of its associated interrupting device operation, complete for each Misoperation without an identified cause:~~ ~~• Development of an action plan that identifies any additional investigative actions and/or Protection System modifications, including a work timetable, or~~ ~~• A declaration explaining why no further actions will be taken.~~ ~~**R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion~~)" portion, and Requirement R6 addresses the "implement" portion of the CAP.

Standard: PRC-004-~~2a~~ – 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
	BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's	~~PRC-004-3 Requirement 4~~ ~~NERC Rules of Procedure, Section 1600 data request~~None.	~~**R4.** Each Transmission Owner, Generator Owner, or Distribution Provider shall implement each CAP or action plan, and revise as needed through completion.~~ ~~N/A~~Since the NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations. NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if

Standard: PRC-004-~~2a –~~ 2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	Translation to ~~New Standard~~PRC-004-3 or Other Action	~~Proposed Language in PRC-004-3 – Protection System Misoperation Identification and Correction or Comment~~ Comments
procedures.		anything, to benefit or protect the reliable operation of the BES.

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction
Project 2010-05.1 – Protection System (Misoperations)

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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: [2]

- 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

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The following discussion addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. " The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection

System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another entity; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause as the fourth discrete requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, the entity must make a declaration why and that no further corrective actions will be taken.

In the last of the requirements, Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new requirements comingle various reliability attributes of the legacy standards with precise reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations, PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation, PRC-016-0.1 – Special Protection System Misoperation, and PRC-022-1 – Under-

Voltage Load Shedding Program Performance, R1 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.
Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection System for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2

VRF and VSL Justifications – PRC-004-3, R1	
	(GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This proposed Requirement R1, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirements R1 and R2 because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R1	
of Compliance	The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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.
FERC VSL G3 Violation Severity Level 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 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R1	
Violations	

VRF and VSL Justifications – PRC-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify a joint owner of a Protection System when the initiating owner determined its components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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. Unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of Protection System components when it determines that (or is unsure whether)its components did not cause a Misoperation or when it is unable to rule out a Misoperation of the jointly owned Protection System. This ensures that all parties review

VRF and VSL Justifications – PRC-004-3, R2	
	their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which as a VRF of High. The requirement and VRF of Medium is consistent with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…") and MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…") which both have a VRF of Medium. Other protection systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of

VRF and VSL Justifications – PRC-004-3, R2			
	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. Unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with

VRF and VSL Justifications – PRC-004-3, R2			
			Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as joint ownership is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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.		
FERC VSL G3	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore		

VRF and VSL Justifications – PRC-004-3, R2	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	consistent with the requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of a joint Protection System owner to review its components for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation upon notification could in the planning time frame, 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. Protection System operations reviewed for proper operation by other owner(s) is an important step in

VRF and VSL Justifications – PRC-004-3, R3	
	preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection System for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which as a VRF of High. This proposed Requirement R1, to “review” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirements R1 and R2 because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R3			
	Failure of a joint Protection System owner to review its components for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation upon notification could in the planning time frame, 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. Protection System operations reviewed for proper operation by other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late.

VRF and VSL Justifications – PRC-004-3, R3			
less than or equal to 30 calendar days late.	greater than 30 calendar days and less than or equal to 45 calendar days late.	than or equal to 60 calendar days late.	OR The responsible entity failed to identify whether or not a Misoperation its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R3	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation could in the planning time frame, under emergency, abnormal, or restorative

VRF and VSL Justifications – PRC-004-3, R4	
	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. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which as a VRF of High. This proposed Requirement R4, to perform at least one “investigative action” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4			
	The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirement because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.		
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement	The responsible entity performed at least one investigative action in accordance with Requirement	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar

VRF and VSL Justifications – PRC-004-3, R4			
R4, but was less than or equal to one calendar quarter late.	R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	quarters and less than or equal to three calendar quarters late.	quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R4	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which have varying VSLs. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The former Requirement for the CAP was limited to a High VSL; however, the proposed Requirement R5 is now expanded to the Severe VSL. The lesser VSLs are based on tardiness and are practical and reasonable for the amount of time allotted for completion.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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. An unresolved cause of a Misoperation could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R5			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.

VRF and VSL Justifications – PRC-004-3, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to develop the CAP with the Lower VSL being based on tardiness of the development.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R5	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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 Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation, through not implementing a Corrective Action Plan, could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which as a VRF of High. The requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirement because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justification – PRC-004-3, R6			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of the requirement that are not equal in importance and performance.		

VRF and VSL Justification – PRC-004-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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 Justification – PRC-004-3, R6	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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.

~~Project 2010-05.1 –~~ Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3~~:~~
– Protection System Misoperation Identification and Correction
Project 2010-05.1 – Protection System (Misoperations)

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project~~:~~.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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:[2]

- 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

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The following discussion addresses how the SDT considered FERC's VRF Guidelines ~~2~~1 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-004-3 – Protection System ~~Misoperations~~Misoperation Identification and Correction is a revision of PRC-004-~~2a~~2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations~~ with the stated purpose: Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.~~ . " The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems ~~required the Regions~~requires Regional Entities to establish procedures for analysis of Misoperations. In ~~the NOPR~~FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The ~~NOPR~~Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-~~2a.~~ 2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-~~2a~~2.1a.

The proposed PRC-004-3 Reliability Standard has ~~four (4)~~six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. ~~The~~First, the revised standard requires ~~entities to identify~~ the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System ~~operations and designate each~~ operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; ~~then investigate each~~ regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another entity; the BES interrupting device owner determined that a Misoperation ~~and document the findings. If a~~ occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause ~~is identified, the entity either creates~~the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause as the fourth discrete requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or ~~writes~~explain in a declaration ~~that they~~why it cannot correct the ~~misoperating device(s). If a cause is not identified, the entity either creates an action plan~~ cause of the Misoperation. In developing a Corrective Action Plan (CAP) for ~~additional investigation or a writes a declaration~~ the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, the entity must make a declaration why and that no further ~~work~~corrective actions will be ~~done. The next step is to~~taken.

In the last of the requirements, Requirement R6, the entity must implement and complete the CAP ~~or action plan. If the action plan leads to the determination of a cause, then the entity would either create a Corrective Action Plan (CAP) or write a declaration. The requirements recognize and encompass the possibility that components of a Protection System can be owned by different entities.~~. The entity must update the CAP during implementation when actions or timetables change.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the requirements of the two legacy standards~~.~~, PRC-003-1 and PRC-004-2.1a. The new requirements comingle various reliability attributes of the legacy standards with ~~new~~precise reliability objectives, thus a requirement-to-requirement comparison of VRFs is not possible. In developing the new VRFs for the requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. ~~The VRFs of the FERC approved PRC-004-WECC-1, EOP-008-1, PRC-004-2a and of TPL-001-2~~The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations, PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation, PRC-016-0.1 – Special Protection System Misoperation, and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1~~, R2 and R3~~ through R6 are assigned a VRF of Medium~~, while Requirement R4 is assigned a VRF of High~~.

~~PRC-004-3 Requirements R1, R2 and R3 are related to identifying Protection System operations, designating Misoperations, investigating Misoperations and developing Corrective Action Plans (CAP) or action plans. The SDT determined that the assignment of a VRF of Medium was consistent with the NERC criterion that states "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…"~~

~~PRC-004-3 Requirement R4 relates to implementing and completing CAPs or action plans. The SDT determined that the assignment of a VRF of High was consistent with the NERC criterion that states "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…"~~

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to ~~identify and~~ review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to ~~designate Misoperations, investigate each~~a Protection System failure to operate for Misoperation ~~and document the findings~~ could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or ~~the~~ capability of the bulk electric system, or the ability to effectively monitor ~~and~~, control, or restore the bulk electric system. ~~Unresolved Misoperations could contribute to more severe~~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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or ~~result in~~potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. ~~The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.~~
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: ~~N/A~~ The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection System for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement ~~has Parts that all support~~single reliability activity associated with the reliability objective ~~so only one~~and no sub-Requirement(s) which allows a single VRF ~~was~~to be assigned; therefore no

VRF and VSL Justifications – PRC-004-3, R1	
	conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: ~~The SDT has assigned a Medium VRF which is consistent with EOP-008-1 Requirement R8 (which is similar in nature to PRC-004-3 Requirement R1.)~~This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This proposed Requirement R1, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirements R1 and R2 because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to ~~identify and~~ review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to ~~designate Misoperations, investigate each~~ a Protection System failure to operate for Misoperation ~~and document the findings~~ could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or ~~the~~ capability of the bulk electric system, or the ability to effectively monitor ~~and~~, control, or restore the bulk electric system. ~~Unresolved Misoperations could contribute to more severe~~ 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or ~~result in~~potential equipment damage. However,

VRF and VSL Justifications – PRC-004-3, R1			
	violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~ The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.~~		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent~~ throughout the requirement~~.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity ~~performed the actions~~identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, ~~Parts 1.1 and 1.2 ~~but in more than 120 calendar days ~~but~~and less than or equal to 150 calendar days of the ~~operation's occurrence.~~ ~~OR~~ ~~The responsible entity identified a Protection System operation that operated one of its ~~BES interrupting ~~devices but failed to review the operation in~~	The responsible entity ~~performed the actions~~identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, ~~Parts 1.1 and 1.2 ~~but in more than 150 calendar days ~~but~~and less than or equal to ~~160~~165 calendar days of the ~~operation's occurrence~~BES interrupting device operation.	The responsible entity ~~performed the actions~~identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, ~~Parts 1.1 and 1.2~~ but in more than ~~160~~165 calendar days ~~but~~and less than or equal to ~~170~~180 calendar days of the ~~operation's occurrence.~~BES interrupting device operation.	The responsible entity ~~performed the actions ~~identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, ~~Parts 1.1 and 1.2~~ but in more than ~~170~~180 calendar days of the ~~operation's occurrence~~BES interrupting device operation. OR The responsible entity failed to identify ~~and review a Protection System operation that operated one of ~~whether or not its ~~BES interrupting devices ~~Protection

VRF and VSL Justifications – PRC-004-3, R1			
~~accordance with Requirement R1, Part 1.1~~device operation. ~~OR~~ ~~The responsible entity completed its review of a Protection System operation that operated one of its BES interrupting devices in 120 calendar days and determined the operation was a Misoperation and failed to document the findings in accordance with Requirement R1, Part 1.2.~~			System component(s) caused a Misoperation in accordance with Requirement R1~~, Part 1.1.~~ ~~OR~~ ~~The responsible entity failed to investigate a Misoperation and document the findings in accordance with Requirement R1, Part 1.2.~~ ~~OR~~ ~~The entity that owns the BES interrupting device but does not own the entire Protection System could not determine if the operation was correct and failed to notify the other owner(s) of the Protection System component(s) and provide any requested investigative information in accordance with Requirement R1, Part 1.1~~.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This ~~VSL is consistent with the current VSL associated with the existing~~ requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard ~~being replaced.~~ . The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: ~~N/A~~ This requirement is not binary; therefore, this criterion does not apply. 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.
~~FERC VSL G3~~ ~~Violation Severity Level 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.~~

VRF and VSL Justifications – PRC-004-3, R1	
~~FERC VSL G4~~ ~~Violation Severity Level 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-004-3, R2~~	
~~Proposed VRF~~	~~Medium~~
~~NERC VRF Discussion~~	~~Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion 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 Parts so only one VRF was assigned.~~
~~FERC VRF G3 Discussion~~	~~Guideline 3- Consistency among Reliability Standards:~~ ~~The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.~~
~~FERC VRF G4 Discussion~~	~~Guideline 4- Consistency with NERC Definitions of VRFs:~~ ~~Failure to develop a CAP for a Misoperation with an identified cause 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. Unresolved Misoperations could contribute to more severe future disturbances affecting a wider area, or result in equipment damage. However, violation of this requirement is unlikely to lead to~~

~~VRF and VSL Justifications – PRC-004-3, R2~~			
	~~bulk electric system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.~~		
~~FERC VRF G5 Discussion~~	~~Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:~~ ~~This requirement does not co-mingle reliability objectives of differing risk; the assigned VRF of Medium is consistent throughout the requirement.~~		
~~VRF and VSL Justifications – PRC-004-3, R2~~			
~~Proposed VSL~~			
~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 60 calendar days but less than or equal to 70 calendar days following the identification of the cause of the Misoperation.~~	~~The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 70 calendar days but less than or equal to 80 calendar days following the identification of the cause of the Misoperation.~~	~~The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, in more than 80 calendar days but less than or equal to 90 calendar days following the identification of the cause of the Misoperation.~~	~~The responsible entity developed a CAP, or a declaration in accordance with Requirement R2, more than 90 calendar days following the identification of the cause of the Misoperation.~~ ~~OR~~ ~~The responsible entity failed to develop a CAP or make a declaration in accordance with Requirement R2.~~

~~VRF and VSL Justifications — PRC-004-3, R2~~	
~~NERC VSL Guidelines~~	~~Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure.~~
~~FERC VSL G1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~This VSL is consistent with the current VSL associated with the existing requirement of the standard being replaced. The proposed VSL does not lower the current level of compliance.~~
~~FERC VSL G2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level 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.~~
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the	The proposed VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with the requirement.

~~VRF and VSL Justifications — PRC-004-3, R2~~	
Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify a joint owner of a Protection System when the initiating owner determined its components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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. Unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

VRF and VSL Justifications – PRC-004-3, R2	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of Protection System components when it determines that (or is unsure whether)its components did not cause a Misoperation or when it is unable to rule out a Misoperation of the jointly owned Protection System. This ensures that all parties review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which as a VRF of High. The requirement and VRF of Medium is consistent with Reliability Standards FAC-008-3 – Facility Ratings, R7 (“…shall provide Facility Ratings (for its solely and jointly owned Facilities…”) and MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 (“…shall provide appropriate equipment characteristics and system data…”) which both have a VRF of Medium. Other protection systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 (“…shall provide documentation…”), PRC-016-0.1 – Special Protection System Misoperations, R3 (“…that owns an SPS shall provide documentation of the misoperation analyses…”), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 (“…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now

VRF and VSL Justifications – PRC-004-3, R2	
	Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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. Unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device

VRF and VSL Justifications – PRC-004-3, R2			
and less than or equal to 150 calendar days of the BES interrupting device operation.	and less than or equal to 165 calendar days of the BES interrupting device operation.	calendar days of the BES interrupting device operation.	operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as joint ownership is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R2	
"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of a joint Protection System owner to ~~develop an action plan~~review its components for ~~a~~ each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation ~~without an identified cause~~upon notification could in the

VRF and VSL Justifications – PRC-004-3, R3	
	planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or ~~the~~ capability of the bulk electric system, or the ability to effectively monitor ~~and~~, control, or restore the bulk electric system. ~~Unresolved Misoperations could contribute to more severe~~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. Protection System operations reviewed for proper operation by other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or ~~result in~~potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. ~~The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion for a Medium VRF.~~
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: ~~N/A~~ The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection System for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement ~~has~~single reliability activity associated with the reliability objective and no ~~Parts so only one~~sub-Requirement(s) which allows a single VRF ~~was~~to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: ~~The requirement is similar to EOP-008-1 Requirement R8 which has an approved VRF of Medium.~~This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations,"

VRF and VSL Justifications – PRC-004-3, R3	
	"develop a Correction Action Plan," and "implement a Corrective Action Plan" which as a VRF of High. This proposed Requirement R1, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirements R1 and R2 because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of a joint Protection System owner to ~~develop an action plan~~review its components for ~~a~~ each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation ~~without an identified cause~~upon notification could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or ~~the~~ capability of the bulk electric system, or the ability to effectively monitor ~~and~~, control, or restore the bulk electric system. ~~Unresolved Misoperations could contribute to more severe~~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. Protection System operations reviewed for proper operation by other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or ~~result in~~potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. ~~The applicable entities are always responsible for maintaining the reliability of the bulk electric system regardless of the situation. This requirement meets NERC's criterion~~

VRF and VSL Justifications – PRC-004-3, R3			
	~~for a Medium VRF.~~		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent~~ throughout the requirement~~.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity ~~developed an action plan,~~identified whether or ~~made~~not its Protection System component(s) caused a ~~d~~Misope~~cla~~ration in accordance with Requirement R3, ~~in more than 180 calendar days~~ but was less than or equal to ~~210~~30 calendar days ~~following the associated BES interrupting device operation~~late.	The responsible entity ~~developed an action plan,~~identified whether or ~~made~~not its Protection System component(s) caused a ~~d~~Misope~~cla~~ration in accordance with Requirement R3, ~~in more~~but was greater than ~~210~~30 calendar days ~~but~~and less than or equal to ~~220~~45 calendar days ~~following the associated BES interrupting device operation~~late.	The responsible entity ~~developed an action plan,~~identified whether or ~~made~~not its Protection System component(s) caused a ~~d~~Misope~~cla~~ration in accordance with Requirement R3, ~~in more~~but was greater than ~~220~~45 calendar days ~~but~~and less than or equal to ~~230~~60 calendar days ~~following the associated BES interrupting device operation~~late.	The responsible entity ~~developed an action plan,~~identified whether or ~~made~~not its Protection System component(s) caused a ~~d~~Misope~~cla~~ration in accordance with Requirement R3, ~~more~~but was greater than ~~230~~60 calendar days ~~following the associated BES interrupting device operation~~late. OR The responsible entity failed to ~~develop an action plan~~identify whether or not a ~~declaration~~Misoperation its Protection System component(s) occurred in accordance with Requirement R3.

VRF and VSL Justifications – PRC-004-3, R3	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This ~~VSL is consistent with the current VSL associated with the existing~~ requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard ~~being replaced.~~ . The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: ~~N/A~~ This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R3	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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-004-3, R4	
Proposed VRF	~~High~~**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to ~~implement~~identify the cause(s) of a ~~CAP or action plan to address an identified~~ Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly ~~cause~~and adversely affect the electrical state or ~~contribute~~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 ~~a~~ cascading ~~sequence of~~ failures~~. Unresolved Misoperations~~, nor to hinder restoration to a normal condition. Unidentified causes of a Misoperation could contribute to ~~more severe~~the severity of future disturbances

VRF and VSL Justifications – PRC-004-3, R4	
	affecting a wider area, or ~~result in~~potential equipment damage.~~ This is a planning requirement that meets the NERC criterion for a High VRF~~ However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report:~~ N/A~~ This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement ~~has~~single reliability activity associated with the reliability objective and no ~~Parts so only one~~sub-Requirement(s) which allows a single VRF ~~was~~to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: ~~The requirement is consistent with PRC-004-2a, Requirements R1 and R2, PRC-004-WECC-1 Requirement R2.1, and TPL-001-2 Requirement R2 Part 2.7 which have approved VRFs of High.~~This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which as a VRF of High. This proposed Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirement because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to ~~implement~~ identify the cause(s) of a ~~CAP or action plan to address an identified~~ Misoperation could in the planning time frame, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly ~~cause~~and adversely affect the electrical state or ~~contribute~~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 ~~a~~ cascading ~~sequence of~~ failures~~. Unresolved Misoperations~~, nor to hinder restoration to a normal condition. Unidentified causes of a Misoperation could contribute to ~~more severe~~the severity of future disturbances affecting a wider area, or ~~result in~~potential equipment damage. ~~This is a planning requirement that meets the NERC criterion for a High VRF~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does ~~contain obligations that are administrative in nature but they support the high risk~~not co-mingle reliability ~~objective;~~objectives of differing risk; therefore, the assigned VRF of ~~High~~Medium is ~~appropriate for the requirement~~consistent.

Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity ~~failed to revise a CAP or~~ performed at least one investigative action ~~plan as needed~~ in accordance with Requirement R4, but was less than or equal to one	~~N/A~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than	~~N/A~~The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late.

VRF and VSL Justifications – PRC-004-3, R4			
calendar quarter late.	or equal to two calendar quarters late.	three calendar quarters late.	OR The responsible entity failed to ~~implement a CAP or~~perform investigative action ~~plan~~(s) in accordance with Requirement R4.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—~~The VSLs cover aspects of~~There is an incremental aspect to the ~~requirement that are~~VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not ~~equal in importance~~by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This ~~VSL is consistent with the previous severity level~~requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance ~~for the similar Requirement~~because the former VSL was comingled with the other activities. The proposed VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single	Guideline 2a: ~~N/A~~ This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:

VRF and VSL Justifications – PRC-004-3, R4	
Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which have varying VSLs. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The former Requirement for the CAP was limited to a High VSL; however, the proposed Requirement R5 is now expanded to the Severe VSL. The lesser VSLs are based on tardiness and are practical and reasonable for the amount of time allotted for completion.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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. An unresolved cause of a Misoperation could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R5			
Proposed VSL			
Lower	Moderate	High	Severe
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.

VRF and VSL Justifications – PRC-004-3, R5	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to develop the CAP with the Lower VSL being based on tardiness of the development.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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-004-3, R5	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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 Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation, through not implementing a Corrective Action Plan, could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: The requirement single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which as a VRF of High. The requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium is not inadvertently lowering the identified VRF of High in the former Requirement because the proposed Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justification – PRC-004-3, R6			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of the requirement that are not equal in importance and performance.		

VRF and VSL Justification – PRC-004-3, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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 Justification – PRC-004-3, R6	
FERC VSL G3 Violation Severity Level 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 Violation Severity Level 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.

A. Introduction

1. **Title:** **Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems**

2. **Number:** PRC-003-1

3. **Purpose:** To ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.

4. **Applicability**

   4.1. Regional Reliability Organization

5. **Effective Date:** May 1, 2006.

B. Requirements

R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:

R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).

R1.2. Data reporting requirements (periodicity and format) for Misoperations.

R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.

R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.

R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.

R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.

C. Measures

M1. The Regional Reliability Organization shall have procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in R1.

M2. The Regional Reliability Organization shall have evidence it maintained and periodically updated its procedures for review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations as defined in Requirement 2.

M3. The Regional Reliability Organization shall have evidence it provided its procedures for the review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in Requirement 3.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Monitoring Responsibility

NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Regional Reliability Organization shall retain documentation of its procedures for analysis of transmission and generation Protection System Misoperations and any changes to those procedures for three years.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Procedures were not reviewed and updated within the review cycle period as required in R2.

2.2. Level 2: Procedures did not include one of the elements defined in R1.1 through R1.4.

2.3. Level 3: Procedures did not include two or more of the elements defined in R1.1 through R1.4.

2.4. Level 4: There shall be a level four non-compliance if either of the following conditions exist:

2.4.1 No evidence of Procedures.

2.4.2 Procedures were not provided to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners as defined in R3.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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.	01/20/06

A. Introduction

1. **Title:** Analysis and Mitigation of Transmission and Generation Protection System Misoperations
2. **Number:** PRC-004-2.1a
3. **Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.
4. **Applicability**
   - **4.1.** Transmission Owner.
   - **4.2.** Distribution Provider that owns a transmission Protection System.
   - **4.3.** Generator Owner.
5. **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.

B. Requirements

R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

C. Measures

M1. The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M2. The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

M3. Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.

D. Compliance

1. **Compliance Monitoring Process**
   - **1.1. Compliance Enforcement Authority**

     Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.

The Compliance Monitor shall retain any audit data for three years.

1.5. Additional Compliance Information

The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	

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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	

Appendix 1[1]

Requirement Number and Text of Requirement
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1. **R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.
Question:
Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?
Response:
The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES. A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.

[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.

Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)
PRC-004-3

Formal Comment Period Open: January 17, 2014 – March 3, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: February 21, 2014 - March 3, 2014

Now Available

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is now open through 8 p.m. Eastern on **Monday, March 3, 2014**.

Background information for this project can be found on the project page.

Instructions

A formal comment period for **PRC-004-3** is open through **8 p.m. Eastern on Monday, March 3, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An additional ballot of **PRC-004-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **February 21, 2014 through 8 p.m. Eastern on Monday, March 3, 2014**.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

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Atlanta, GA 30326
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Standards Announcement

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)
PRC-004-3

Formal Comment Period Open: January 17, 2014 – March 3, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: February 21, 2014 - March 3, 2014

Now Available

A formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is now open through 8 p.m. Eastern on **Monday, March 3, 2014**.

Background information for this project can be found on the project page.

Instructions
A formal comment period for **PRC-004-3** is open through **8 p.m. Eastern on Monday, March 3, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps
An additional ballot of **PRC-004-3** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **February 21, 2014 through 8 p.m. Eastern on Monday, March 3, 2014**.

Standards Development Process
The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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RELIABILITY CORPORATION

Standards Announcement

Project 2010-05.1 Protection Systems: Misoperations
PRC-004-3

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot of **PRC-004-3 – Protection System Misoperation Identification and Correction** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, March, 11 and Wednesday, March 12, 2014** respectively.

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
75.06% / 62.63%	75.00% / 69.06%

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 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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-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-05.1 Protection Systems: Misoperations PRC-004-3
Ballot Period:	2/21/2014 - 3/11/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	313
Total Ballot Pool:	417
Quorum:	**75.06 % The Quorum has been reached**
Weighted Segment Vote:	62.63 %
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	110	1	56	0.667	28	0.333	0	3	23
2 - Segment 2	9	0.2	1	0.1	1	0.1	0	6	1
3 - Segment 3	102	1	43	0.614	27	0.386	0	6	26
4 - Segment 4	33	1	15	0.714	6	0.286	0	2	10
5 - Segment 5	92	1	34	0.54	29	0.46	0	4	25
6 - Segment 6	52	1	24	0.585	17	0.415	0	1	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	10	0.3	2	0.2	1	0.1	0	0	7
9 - Segment	2	0	0	0	0	0	0	0	2

9									
10 - Segment 10	7	0.6	4	0.4	2	0.2	0	1	0
Totals	**417**	**6.1**	**179**	**3.82**	**111**	**2.28**	**0**	**23**	**104**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Kirit Shah	Negative	COMMENT RECEIVED
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz -AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
				SUPPORTS THIRD PARTY

1	Gainesville Regional Utilities	Richard Bachmeier	Negative	COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power)
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	COMMENT RECEIVED - Brett Holland
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
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		
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	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted under PPL NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSE&G supports Public Service Enterprise Group that will be submitting comments by Mar 3)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman, Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
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	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED

1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn		
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Abstain	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz of American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
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	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Clearwater Power Co.	Dave Hagen		
				SUPPORTS THIRD PARTY

3	Cleco Corporation	Michelle A Corley	Negative	COMMENTS - (See SPP Comments)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	COMMENT RECEIVED
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED - Brett Holland
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT

				RECEIVED
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - NSRF
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	COMMENT RECEIVED
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	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Orange and Rockland Utilities, Inc.	David Burke	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	Pacific Northwest Generating Cooperative	Rick Paschall		
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group (PSEG))
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	COMMENT RECEIVED
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
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	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson - Tacoma Power)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED

3	Turlock Irrigation District	James Ramos		
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Stds Group)
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson & Barb Kedrowski)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
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	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson

				and Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren's comments)
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Bridgeport Energy	Cleyton Tewksbury		
5	Caithness Long Island, LLC	Jason M Moore		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP comments)
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Abstain	
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aces Power marketing)
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	El Paso Electric Company	David Hawkins		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	COMMENT RECEIVED
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT

				RECEIVED
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		
5	Lower Colorado River Authority	Tom Foreman		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
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)
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	COMMENT RECEIVED
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group (John Seelke))
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	

5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	COMMENT RECEIVED
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	Turlock Irrigation District	Marty Rojas		
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson & Barb Kedrowski)
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz AEP)
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	COMMENT RECEIVED
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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	COMMENT RECEIVED
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit		
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	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
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	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
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 - (Chris Mattson)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Turlock Irrigation District	Amy Petersen		
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP

				Standards Group)
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	COMMENT RECEIVED - Alice Ireland
8		Edward C Stein		
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

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Non-Binding Poll Results

Project 2010-05.1 Protection Systems: Misoperations
PRC-004-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-05.1 Non-binding Poll - Protection Systems -Misoperations
Poll Period:	2/21/2014 - 3/12/2014
Total # Opinions:	291
Total Ballot Pool:	388
Ballot Results:	75.00% of those who registered to participate provided an opinion or an abstention; 69.06% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Negative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
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 Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED

1	City Utilities of Springfield, Missouri	Jeff Knottek		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aces Power)
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	

1	Kansas City Power & Light Co.	Michael Gammon	Negative	COMMENT RECEIVED - Brett Holland
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	COMMENT RECEIVED
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
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		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		

1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted under PPL NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Karen Silverman, Puget Sound Energy)
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	Southern California Edison Company	Steven Mavis	Negative	COMMENT RECEIVED
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	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	

1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn		
1	Western Farmers Electric Coop.	Forrest Brock		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Abstain	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon		
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 Services	Mark Peters	Abstain	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
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	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	

3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED - Brett Holland
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS -

NERC

				(Florida Municipal Power Pool)
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	COMMENT RECEIVED
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS-NSRF
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	Pepco Holdings, Inc.	Mark R Jones	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	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	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	

4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dale Fredrickson and Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Bridgeport Energy	Cleyton Tewksbury		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Abstain	
5	Detroit Renewable Power	Marcus Ellis	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	

5	East Kentucky Power Coop.	Stephen Ricker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Aces Power Marketing.)
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Negative	COMMENT RECEIVED
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	COMMENT RECEIVED
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
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)
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Negative	
5	Oklahoma Gas and Electric Co.	Kim Morphis		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	Proven Compliance Solutions	Mitchell E Needham		
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	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	Southern California Edison Company	Denise Yaffe	Negative	COMMENT RECEIVED
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (MRO NSRF)
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	COMMENT RECEIVED
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (See SPP Comments)
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Negative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
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	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	COMMENT RECEIVED
6	Modesto Irrigation District	James McFall		

6	Muscatine Power & Water	John Stolley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Scott Bos)
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
10	Midwest Reliability Organization	William S Smith	Affirmative	

10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (63 Responses)
Name (43 Responses)
Organization (43 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (5 Responses)
Comments (63 Responses)
Question 1 (56 Responses)
Question 1 Comments (58 Responses)
Question 2 (54 Responses)
Question 2 Comments (58 Responses)
Question 3 (52 Responses)
Question 3 Comments (58 Responses)
Question 4 (50 Responses)
Question 4 Comments (58 Responses)
Question 5 (0 Responses)
Question 5 Comments (58 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
We agree with the requirements as revised, but do not agree with Measures M2 and M3. a. Measure M2: The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. b. Measure M3: The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated.
No
We agree with the requirements as revised, but do not agree with the Measures. Measures: The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. The term “investigative

action(s)" is ambiguous even given the example cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard.
a. The "Effective Dates" section of the standard is confusing as it suggests no regulatory (i.e. FERC) approval is required in Western Interconnection and offers both twelve and twenty-four month timeframes. b. Applicability Section – Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs a similar function when initiated by abnormal voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. c. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. d. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. e. VSL for R3: Second condition under SEVERE - similar comment as for the VSL for R1 preceding. f. The SDT should reconsider the need for the defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. The comment report indicated that 4 commenters representing 24 individuals requested clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing the redundant new term.
Group
Puget Sound Energy
Dianne Gordon
No
a) Misoperation Definition #3 (Slow Trip – During Fault) would require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. b) Misoperation Definition #4 (Slow Trip – Other Than Fault) would also require the running of system studies to test for possible system

instability. This (and/or other expectations) should be spelled out in the Application Guidelines. c) For #2 & #4 sections of the Misoperation Definition as well as under Facilities (4.2.2) - UFLS/UVLS both should specifically be mentioned together. d) It should be clarified that non-fault tripping protection schemes as described in PRC-004-3 do not include RAS/SPS (and that RAS/SPS will be covered in PRC-016). e) It should be clarified in PRC-004-3 that UFLS/UVLS are not specifically part of the RAS/SPS definition (even though this is spelled out in the NERC glossary). Otherwise, it all can be quite confusing. f) In all six parts of the Misoperation Definition, the phrase "…where tripping for protection purposes is involved" could be included for clarity.
Yes
Yes
No
a) Application Guidelines could have more specificity, in addition to examples. For example, in #4 (Slow Trip – Other than Fault), it should be spelled out that each possible Misoperation should be studied to test for possible effects on system stability. Other specific expectations, if any, should also be spelled out. b) In addition, "Other than Fault" should be clarified and explained together with the definition of SPS/RAS, which are excluded from PRC-004. (SPS/RAS are defined as non fault protection schemes). c) UFLS/UVLS should always be mentioned together in PRC-004-3 (unless both are not included). d) Should sync check and breaker failure be considered in the Application Guidelines – what category do these fall into? e) In all six parts of the Misoperation Definition, the phrase "…where tripping for protection purposes is involved" could be included for clarity.
a) Under Facilities on p.5, UFLS /UVLS should both be listed, if intended. The order of facilities (specifically content of 4.2.1 and 4.2.2) should be swapped – so that everything INcluded comes before everything EXcluded. b) There should be a whole section clarifying exclusion of SPS/RAS (but inclusion of UFLS/UVLS). Or….the definition of SPS/RAS should be changed to include UFLS/UVLS. c) A Misoperation Process Benchmark table of reporting functions and dates should be provided to entities. This would greatly facilitate retention of misoperation timeline evidence (for audits, self-cert, data requests). The Misoperation Process Benchmark table structure could be provided by the Regional Entities such as WECC in an updated misoperation Criterion as an Appendix. A suggested list of Benchmark dates is as follows: 1. date of Interrupting device operation, 2. date of identification of misoperation, 3. date other owners of Protection System (of BES interrupting device operation) notified, 4. date of identification by notified entity whether its device caused a misoperation, 5. date the cause of misoperation investigated/found, 6. date of further investigation (if cause not found) 7. date of Corrective Action Plan (CAP) development 8. target CAP completion date(s), actual CAP completion date d) Finally, it is recommended that Quarterly Misoperation Reporting be changed over to a "Data Request" sooner than the effective date of PRC-004-3. It is stated on page 5 of the proposed PRC-004-3, that the currently reporting system is "not optimal to establish consistent metrics for measuring Protection System

performance”. Perhaps the ERO Reliabililty Assessment and Performance Analysis Group could release an updated recommendation letter for Misoperation Reporting. It is also recommended that the Misoperation “Data Request” occur once per year.
Group
US Bureau of Reclamation
Erika Doot
No
The Bureau of Reclamation (Reclamation) requests that the drafting team clarify the bounds of the Composite Protection Systems definition. Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems.
Yes
Yes
No
Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems.
Reclamation thanks the drafting team for their efforts refining the standard and providing the examples in the Application Guidelines.
Individual
William H. Chambliss, Member, Operating Committee
Virginia State Corporation Commisison
No
Minor suggestion in Parts 1 and 2 "Faliure to Trip." I suggest changing the phrase "failure of a Protection System component" to "failure of any Protection System component." Although it may be a remote possibility, more than a single component may fail, while the Composite Protection System as a whole acts correctly.
No
R1 remains very unclear to me. The text requires a TO, GO or distribution provider to "identify whether" its component caused a misoperation, but Subparagraph 1.3 requires, as a necessary condition to such identification that the "BES interrupting device owner [has] identified" that its component caused the failure. This is circular.
Yes

I have one wording suggestion for R3. I suggest moving the words "shall identify" from their present location to follow immediately after "Requirement R2." The sentence would then read "Each TO, GO and Distribution Provider that receives notification pursuant to Requirement R2, shall identify within the later of 60 days.....device(s) operation, whether its Protection System component(s) caused a Misoperation."
Yes
Under R5, the owner of a Protection System component that causes a Misoperation shall either develop a CAP or "Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability....." I wonder whether the Requirement should identify to whom and by what manner any such "declaration" should be made?
Group
JEA
Tom McElhinney
Yes
Yes
R1 & R3 both need an exclusion for any declared natural disasters. We also believe that the 60 day timeframe identified in R5 to develop a Corrective Action Plan and evaluate applicability is not sufficient to consider applicability to other PS, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. We recommend this be changed to 180 days.
Individual
Michelle R. D'Antuono
Ingleside Cogeneration, L.P./Occidental Chemical Corporation
No
Ingleside Cogeneration, L.P. (“ICLP”) agrees that the definition of “Composite Protection System” properly captures the concept proposed by the project team. It reflects an intent that a Misoperation is determined by evaluating the actual performance of the primary, secondary, and pilot systems in totality against the expected performance. Evaluations of individual schema failures are of little value when built-in redundancy takes over to protect the local system – exactly as the designers intended. There is still discomfort with the definitions of “Slow Trip – During Fault” and “Slow Trip – Other Than Fault” – particularly in those cases where the design responsibility is out of our hands. For example, when PRC-024-1 takes effect, Generator Owners will have little control over the expected performance of

voltage and frequency-responsive Protection Systems – provided the relays are set in accordance with the standard. This means that the definitions need to include a statement that any composite Protection System operation that reacts consistently with the parameters (settings) established in any other NERC standard cannot be a Misoperation. Secondly, unless notified by the Transmission Planner or Planning Coordinator, ICLP will not know that the Misoperation of one of our Protection Systems will lead to BES "voltage or dynamic instability." The two definitions seem to recognize that the GO may not be in a position to be identify such critical Protection Systems, but can be read otherwise. Similar to the previous issue, we believe that as long as we correctly supply modeling data to the TP and PC in accordance with other NERC standards, the responsibility to identify susceptible Protection Systems remains with the planning entities.
Yes
ICLP believes that the latest draft of PRC-004-3 corrects a gap where a delayed investigation by one entity could lead to a finding of a violation on the other. Requirements R2 and R3 address this potentially unfair scenario.
Yes
ICLP appreciates the precise language used in Requirement R4 – which allows sufficient time to investigate a Misoperation, while limiting it to within reasonable bounds. We agree that if a cause cannot be found through good faith investigation within two calendar quarters, there is little benefit to pursuing the case further.
Yes
ICLP is concerned that Compliance Enforcement Entities' interpretation of PRC-004-3 will evolve over time – particularly as new Protection System vulnerabilities are found through the evaluation of Misoperations. In addition, the need for greater numbers of measuring points and the increased granularity of Disturbance data will naturally grow as relay schemes become more and more complex. This means that a clear expectation of the requirements for Disturbance Monitoring Equipment (DME) must be established up front in a binding fashion. We accept the project team's assertion that PRC-002-2 (presently under development) is the proper vehicle for the identification of required DME locations, but would like to see a clear tie to PRC-004-3. Otherwise it is easy to see that CEAs may decide at a future date that Misoperations' reporting needs are the driving factor for DME, not PRC-002-2.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes

Yes
Yes
Individual
Anthony Jablonski
ReliabilityFirst
No
Throughout the draft standard (and definition of Misoperation), the term “Composite Protection System” is used while in other portions only the term Protection System is referenced. For example, within the definition of “Misoperation”, items one through four use the term “Composite Protection System” while items five and six use the term “Protection System”. Another example is Requirement R1, Part 1.1 references the term “Protection System” while Part 1.2 references “Composite Protection System”. ReliabilityFirst request the SDT’s rationale on the appropriateness of the use of these terms.
No
The term “BES interrupting device” is used throughout Requirements R1, R2 and R3 though it is only defined within the Application Guidelines section. In order to provide clarity and avoid potential interpretations of what constitutes a “BES interrupting device”; ReliabilityFirst recommends the SDT propose this as a new definition which would be added to the NERC Glossary of Terms. ReliabilityFirst recommends the following definition from the Application Guidelines for consideration: “BES Interrupting Device - A BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current.”
No
ReliabilityFirst has a number of concerns with Requirement R4. First, from compliance/enforcement perspective, Requirement R4 is not sufficiently distinct from Requirements R1 and R3 (it creates a “double jeopardy situation”). For example, Requirement R3 requires the responsible entity to “…identify whether its Protection System component(s) caused a Misoperation”. As written, if the responsible entity fails to “…identify whether its Protection System component(s) caused a Misoperation” this could be grounds for a possible violation of Requirement R3. This is evident in the associated Violation Severity Levels where failing “…to identify whether or not a Misoperation its Protection System component(s) occurred” is a Severe Violation. This is in direct conflict with Requirement R4, which gives the responsible entity additional time to perform investigation actions to determine the cause of the Misoperation. ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish but from a compliance/enforcement standpoint it will cause issues. Second, as already noted, ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish, but notes that there is no ending time period associated with how long the responsible entity has to complete the investigation. As

written, a responsible entity can hypothetically drag out the investigations and never officially complete the investigation. ReliabilityFirst believes in order to close the loop, the responsible entity should be limited to four calendar quarters to complete the investigation (i.e., either identification of the cause(s) of the Misoperation or declaration that no cause can be identified). To address the two concerns, ReliabilityFirst recommends including similar language as noted in Requirement R4 as sub parts in Requirement R1 and R3 along with including an ending completion timeframe as well. The following is an example for consideration for Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. If the cause(s) of the Misoperation cannot be determined, the Transmission Owner, Generator Owner, and Distribution Provider shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters, but for no more than four calendar quarters after the Misoperation was first identified, until one of the following actions completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
We suggest revising #6 Unnecessary Trip –Other Than Fault: replace the 2nd sentence as follows: Current wording: “A Protection System operation that is caused by on-site maintenance, testing, …is not a Misoperation” Suggested wording: “A Protection System operation that is related to on-site maintenance, testing, … is not a Misoperation”. This provides some flexibility to exclude operations not directly caused by on-site activity, but is a consequence of such activity.
No
There appears to be a gap between R1 and R2 for the case when an interrupting device operates, but the interrupting device owner does not own any part of the Protection System(s) that tripped or may have tripped the device. The assumption in the draft is that the interrupting device owner also owns a portion of the Protection System, but this may not always be true.
Yes
No
The examples 8a and 8b under Control Functions should be clarified to help entities make proper distinctions between control functions and protective functions of reverse power

relays. We suggest the wording in the paragraph following Example 8b be revised as follows: Current wording: In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System’s reverse power protective function as a normal procedure to shutdown a generating unit. Suggested wording: In the examples above, the standard is not applicable because the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System to protect turbine-generators from motoring. Entities often take advantage of this functionality and use the Protection System’s reverse power function as a part of a normal procedure to shutdown a generating unit. However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit.
Individual
Shirley Mayadewi
Manitoba Hydro
No
(1) Manitoba Hydro believes that the definition of Misoperation needs to be re-written for the following reasons: a. It is not clear whether the six categories of Misoperations is exhaustive. The definition should be revised to clarify this. b. Under category 3, it is not clear if the cited example is the only type of Misoperations. c. Use of the phrase “slower than required” in category 3 and 4 of the definition is unclear and does not capture the intended meaning identified in the Application Guidelines. The Guidelines state that “required” actually means as intended by the owner. Thus, this terminology should be used. d. Based on the numerous examples in the Guidelines of what is and is not a “Misoperation”, as well as references in the Guidelines to the effect that SMEs recognize that judgment must be used, the definition itself should clearly incorporate the notion of judgment by the owner. While the first sentence of the definition refers to intention, it does not specify whose intention (manufacturer, designer, operator..?) e. The sentences about component failure are out of place given that the definition of Composite Protection System is the total system, not individual components, and given that the first sentence of the definition refers specifically to failure of the Composite Protection System. f. The word “intended” has been replaced with “required” even though the Application Guideline states that the term “required” is intended to refer to the objective of the owner. If this is the intended meaning, then the standard should use the wording “as intended by the owner”. The words “as required” are too vague and may be interpreted to mean as required to ensure the reliability of the BES. (Could it also mean as required by the designer / manufacturer or some other entity?) (2)

Revise the definition of Composite Protection System to “The total complements of the Protection System(s) that function collectively to protect an Element, such as A and B system, any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.”
Yes
No
(1) For R4, Manitoba Hydro does not think that there is a need to perform investigative actions to determine the cause of the Misoperation at least once every two full quarters. Repeated investigative actions would not be productive in identifying the cause. We propose this requirement to read as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation, until one of the following is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.”
Yes
(1) PRC-004-3, Application Guidelines, Extenuating Circumstances - for clarity, replace the word “says” with the word “reads”.
(1) R4, second bullet - for consistency with the previous bullet, rephrase to read “A declaration that no cause(s) were identified.” (2) R5, second bullet - because it’s possible that a single corrective action can be taken, add brackets around the “s” in the word “actions”. (3) R6 and M6 - for consistency with other requirements in the standard, replace the word “actions” with “corrective action(s)”. (4) R1 and R2 a. Use of the past tense (i.e. "that operated") is inappropriate for statutory / regulatory standards. The wording should be: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device shall, within 120 calendar days of the operation of the BES interrupting device...". b. Similarly, in R2.2 and 2.3 , the word "determined" should be replaced with "has determined". c. Use of the word "when" implies a time frame. Given the intent, it would be clearer to use the phrase "under the following circumstances". (5) R5 - for the reasons identified above, the use of past tense should be changed to:" Each Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System Component that causes a Misoperation ...". (6) The wording of R6 makes the compliance obligation unclear. Part of the requirement requires implementation of a CAP. However, another part of the requirement allows updating and changing the CAP. Accordingly, it can be inferred that some deviation from the CAP, and thus failure to implement the CAP, will still be considered compliance. A review of the Application Guidelines also confirms that rescheduling actions under the CAP is permitted in at least some cases. The criteria for acceptable revisions should be clarified in R6 (ex.- do they need to be beyond the reasonable control of the Responsible Entity?).
Individual
David Kiguel

David Kiguel
Yes
No
The standard should require that the Connection Agreement(s) among owners must address the procedures and potential dispute resolution for the case of 2 or more owners involved in the Misoperation investigation and CAP.
As written, the draft standard leaves a void that should be filled. A mechanism must be provided to allow for verifying that the conclusions of the investigation are correct, the CAP is appropriate and overseeing its completion within the planned time. Typically, this would be a responsibility that could be assigned to the Reliability Assurer (RA) as defined in the BoT approved Functional Model. The FM definition of RA fits this role well. However, since no entities are registered as RA at this time and it is unlikely there will be in the future, a second choice would be assigning such responsibility to the Planning Coordinator (PC). Suggest adding an additional requirement assigning such responsibility to the RA (or the PC if the SDT decides so): Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall submit its investigation report and CAP documentation to the Reliability Assurer (or Planning Coordinator) that has responsibility for the area in which the associated devices are located, within 21 calendar days of their completion. The RA (or PC) shall review and either approve or provide comments within 60 calendar days of the submission.
Individual
Catherine Wesley
PJM Interconnection
Yes
Yes
Yes
Yes
Individual
Russ Schneider

Flathead Electric Cooperative, Inc.
No
I do not like adding composite to the definition of protection system. This seems to broaden what is understood as a protection system and may impact testing and maintenance programs unnecessarily. I suggest sticking with the way it was before this redline change.
Yes
No opinion on this change.
No
I do not believe that UFLS equipment should be included under this standard.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
We strongly believe that the drafting teams need to understand how the standards they are developing will interact with other NERC standards and documents. There may be unintended consequences when the relationships between two standards or other NERC documents are not foreseen. Regrettably, the SDT for the new BES Definition failed to take into account the substantial impact of its product on the various standards that would be applied to the new BES elements. Therefore it is critical for the PRC-004-3 SDT to take a step back and anticipate the effect of the new BES definition on this standard. The case in point is the addition of dispersed generators to the BES. We remain very concerned with the effort that will be required to comply with this standard in light of the new BES facilities that are included in the new BES definition, especially dispersed generation. It is wind that especially troubles us. We have about 200 wind turbine generators in our fleet, all less than 2 MW in size. Wind makes up less than 5 % of our generation capacity. Yet, in terms of the sheer number of generators, the number of wind units is roughly 5 times the number of other larger generators in our fleet. Of these 200 wind generators, 90% will soon become BES generators due to being aggregated in facilities above 75 MVA. It is the outsized impact of these wind turbines that will have a huge effect when we are required to analyze in depth each protection system operation of these wind generators in order to comply with PRC-004-3. This effort will be enormous, and yet the reliability benefit is negligible. The valuable technical resources available at my company, and at many other companies with even larger amounts of dispersed generators, are not best utilized by applying this standard at the level

of individual wind generators, and other similar small dispersed generators. To allow entities to focus limited technical resources on efforts that truly enhance reliability, the SDT should revise the Applicability to specifically exclude small dispersed generators, and only apply it where the aggregated generation exceeds 75 MVA, that is, to the collector bus and transformer (with the high-side winding operated at or above 100 kv) used to connect to the transmission system. We believe the extra time it takes to think this through will be worthwhile to the industry, and may prevent inadvertent outcomes that may not serve the overall reliability of the bulk power system.
Individual
Scott Bos
Muscatine Powerand Water
Yes
No
To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, MP&W proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden. Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: 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. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard.

No
MP&W believes that there are many potential forms of “owners” and that “owners” needs to be modified to read, “other NERC registered applicable entities” to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don’t have any impact on the operation of the protection systems.
Yes
MP&W is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. MP&W also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue.
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
No
To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, the NSRF proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden. Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: 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. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard.
No
The NSRF believe that there are many potential forms of “owners” and that “owners” needs to be modified to read, “other NERC registered applicable entities” to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don’t have any impact on the operation of the protection systems.
Yes
: The NSRF is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. The NSRF also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
ATC agrees with the new and revised definitions, but recommends additional clarification around Slow Trip. Would a study be needed to indicate where high-speed performance was previously identified for a Slow Trip? The Slow Trip definitions infer that in order to correctly or incorrectly declare a Misoperation, a study would need to occur. Such study would need to pre-date the operation.
Yes
No
ATC’s experience has been that the cause of a Misoperation is determined within the first couple months following its occurrence. If the cause is not found in that time, it is unlikely to be found. Relative to R4, the parameters around investigative actions are not very productive, as revisiting the same information after an extended period of time does not typically lead to determining a cause. ATC recommends removing the language in R4 that speaks to investigative steps “at least once every two full calendar quarters after the Misoperation was first identified.”
Yes

Individual
Martyn Turner
LCRA Transmission Services Corp
Yes
Yes
Yes
No
LCRA TSC recommends the SDT address the topic of temporal aggregation within the Application Guidelines. For example, if a transmission line over-trips for an out-of-section fault three times in a 2-hour interval, perhaps due to persistent storm activity before a relay setting adjustment can be made, does this count as three misoperations, or can the three events of a similar nature and cause be “collapsed” into a single misoperation? Some guidance in this area would be helpful in order to allow entities to be consistent in reporting. LCRA TSC recommends some way to collapse/combine misoperation events of a similar nature within a short, defined timeframe.
no
Individual
Oliver Burke
Entergy Services, Inc.
Yes
There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate? The definition of Composite Protection System is still vague to this. Suggest the below definition: The total complement of the Protection System(s), with respect to the protective relay of interest, that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.
Yes
Yes
Yes

Look at response to question one.
Required Protection System Misoperation identification and evidence in support of R1 could be interpreted to include all scheduled or manual interrupting device operations, which we believe is not and should not be the intention. Either way, suggest rewording R1 to include the applicable Protection System governing criteria by integrating R1.1 (revised) into requirement R1 as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated due to a Protection System operation or a Protection System failure to operate as designed shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when:”
Individual
Jonathan Meyer
Idaho Power Company
Yes
Yes
Yes
Yes
Individual
Thomas Foltz
American Electric Power
No
AEP recommends replacing “high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability” with “the lack of high-speed performance resulted in voltage or dynamic instability”. The draft does not specify who is responsible to perform the identification, and adding “Planning Authority” would create a de facto TPL requirement.
No
1) AEP recommends revising R1 section 1.2 as follows to recognize that a BES interrupting device may be part of multiple Composite Protection Systems: “The BES interrupting device owner owns all or part of the Composite Protection System(s); and”. 2) AEP recommends revising R2 section 2.1 as follows: “The BES interrupting device owner shares the Composite Protection System(s) ownership with any other entity; and”. 3) AEP recommends adding the

following footnote to the "entity" reference in R2 section 2.1: "In this context, "entity" denotes functional entity. A Composite Protection System owned by different functional entities within the same registered entity satisfies the R2 section 2.1 criteria." 4) AEP recommends adding the following footnote to the "entity's" reference in the first bullet of R5: "In this context, "entity" denotes functional entity". 5) AEP recommends adding the following footnote to the "120 calendar days" reference in R2 and R3: "This timeframe may be extended, for operations occurring within a specified time period, by the Regional Entity if it determines that extenuating circumstances such as a natural disaster make it impractical to complete R1 or R2 within the allotted timeframe".
Yes
AEP recommends replacing "at least once every two full calendar quarters after the Misoperation was first identified" with "at least once every six month period after the Misoperation was first identified".
No
1) AEP recommends adding an example to the applications guideline to illustrate whether repeated operations/misoperations which occur during the same automatic reclosing sequence need a separate identification under R1. 2) AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a "slow trip" type misoperation. 3) AEP recommends adding an example to illustrate how breaker failure fits into composite protection system. 4) AEP recommends adding an example where a misoperation is initially identified, but subsequent investigation (after 120 days) reveals a misoperation did not occur.
AEP believes the draft is very close to being ready for final ballot. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. Our negative vote does not reflect disagreement on the direction or intent of the standard. Rather, it is driven by a number of smaller issues that, in total, would prove problematic in consistently applying the standard.
Individual
Don Schmit
Nebraska Public Power District
Yes
Please clarify the following; the composite protection system also includes the potential transformers, current transformers, battery bank and charger?
Yes
Yes
No

The application guidelines state: “The CAP is complete when all the documented actions to resolve the specific problem (i.e.,Misoperation) are completed which may include those actions resulting from the entity’s evaluation of other locations, if not addressed through a separate CAP.” In the example R6b it appears the CAP is completed and a program was established for corrections at other locations. Please clarify if a program to address other locations is or is not required to be tracked as part of PRC-004 evidence. In the example, it appears the program for other locations does not need to be tracked for PRC-004 evidence. Is this up to the entity to determine?
It seems like the scope for the CAP that must include an evaluation of other Protection Systems including other locations to be completed is very open ended. The concern is what an audit team’s latitude will be with reviewing and accepting or not accepting the subjective nature or these evaluations for other locations. Can the SDT comment how an evaluation that was completed for other locations as part of a misoperation might be addressed in an audit? For example, if a misoperation occurs due to a setting error and an entity decides not to review every relay setting on their system is it possible for an audit team to disagree with this evaluation and create any potential violations? It is recommended the section 1600 Misoperation Draft Template language should match PRC-004-3. It would be quite odd to have the evaluations requirements and a data submissions request use different language. The portion of R6 that states “and update each CAP if actions or time tables change, until completed” seems excessive and granular in nature and adds a lot of detail tracking and difficulty in auditing. It is enough to require a corrective action plan be implemented and close the plan when the final objectives are completed. R4 provides the long term tracking and scheduling. This portion of R6 should be removed. Another option would be to use similar language as in R4.
Individual
Chris Scanlon
Exelon
Yes
We support the definition for Composite Protection System.
No
Please address who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. Otherwise we have no concerns with R1. For R2 and R3, the date timeframes for a shared responsibility Protection System to a common interrupting device short cycles the non-owner of the interrupting device. A suggestion for shared responsibly; With R2 - the BES device owner should notify the Other Protection System owners within 30 calendar days of the operation and the device owner has 120 days calendar days to identify

if it’s Protection System caused a misoperation. For R3, the notified Protection owner should then have 120 from notification to identify if its Protection System misoperated. This time frame for R3 would provide the non-owner sufficient time for any scheduled outages to make a determination.
No
How soon after a misoperation can a declaration of no cause be submitted? Exelon agrees that a prompt investigation of the event should occur and prudent corrective action be initiated as detailed in the new Requirement R4; however, if the Standard is allowing a provision for continued investigations then the other requirements in the Standard should align. Requirement R4 needs to be modified or R1 needs to be modified to align with each other. The current wording in R4 provides a requirement that cannot be met unless the entity is not in compliance with R1. R3 provides the wording such as "cannot rule out" and "or cannot determine". This wording needs to also be added to R1 for completeness. In addition, the wording in the VRFs and VSLs needs to be adjusted to accommodate those events where the cause of the interrupting device operation has not yet been determined.
Yes
The concept of the Application Guideline (AG) is an excellent tool to retain the thought process behind the development of the standard. Use of an AG in this and future standards will help greatly with the understanding, application, and consistency of the standards. Generally, the applications are sufficient for the purpose. Specific comments for clarification include: In “Unnecessary Trip – Other Than Fault”, in the paragraph after Example 6d, the “on-site” maintenance activities section needs more clarity. Is the intent of that paragraph trying to say, if the BES Protection System equipment clearly misoperated and personnel had nothing to do with it, then it’s a PRC-004 misoperation. If the BES Protection System equipment appeared to misoperate, but it’s clear that personnel had something to do with that operation, it’s not a PRC-004 misoperation? For a Communication System, does the “on-site” activities exemption apply to anywhere along the communication path were personnel caused what would otherwise look to be a BES Protection System misoperation?
This draft is a significant improvement over the last draft, specifically because of the addition of the “Composite Protection System”. We also endorse the use of the rationale boxes within the standard; they lend additional clarity to the requirements of the standard. However, consistent with our comments above, the standard is too prescriptive. For example, there is far too much emphasis on documenting dates. Additionally, most of the VSL’s should be eliminated and labeled “N/A”, e.g., on R3, does 30 calendar days really matter? Lower VSL should be up to 60 days late, Moderate is N/A, High is N/A, Severe is more than 60 days late which equals failed to identify. ComEd also disagrees with the VSL tables because they disproportionately propose to punish a larger utility with more operations (and misoperations). There also needs to be a distinction between analyzing automatic operations for misoperations but failing to identify a misoperation in, as an example, 1 out of 100 operations verses taking no effort to identify any misoperations. For these reasons we think the current revision to PRC-004-3 is overly prescriptive and complicated. Suggest that the SDT should evaluate simplifying the Standard to the basic

purpose which is to "identify and correct the causes of Misoperation of Protection Systems for BES elements" without introducing hard timelines, overly prescriptive communication requirements, and documentation of the level of corrective actions performed. Guidelines and Technical Basis: (1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. Can the drafting team provide an example for generator protection similar to the one provided for the transmission line protection? (2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation. If the generator is tripped by another relay say out of step, should it still be called misoperations?
Group
FirstEnergy Corp
Richard Hoag
No
Composite Protection System as a new definition is unclear within the context of a Generating Unit as a BES Asset. Protection System, by definition, is already a composite of the five identified components, as applicable. We do not understand the intent of adding the word Composite, or how it changes the current definition of a Protection System for a Generating Unit.
No
R1 and R2 refer to identification and notification "… within 120 calendar days of the BES interrupting device operation …". Currently, submittals to the Regional Entity are due 60 days following the end of a quarter, which could conceivably place it up to 150 days following an event. Besides having to move up the review of Protection System operations, what Evidence will be required to prove the 120 day identification and notification?
No
Does NERC intend to be prescriptive with respect to a template for a Corrective Action Plan, or will the Regional Entities accept whatever format and tracking documentation is provided by the Registered Entities, even though they may be varied among the Entities? The measures identified in M6 seem as though they could be subject to interpretation by an Auditor.
No
None of the Requirements address notifying the Regional Entity on a periodic basis, as is done now (quarterly for RFC). Is it going to be up to the Regional Entity to identify: a. Whether periodic data submittals will be required? b. If so, the periodicity and the template / format for those data submittals?
For FirstEnergy, the "BES interrupting device" (GCB or Generator Circuit Breaker) is typically owned by the TO, due to the location of the POI (Point of Interconnection). However, the Protection System devices which operate the GCBs are owned by the GO. Regardless the

ownership, the GO certainly knows when the “BES interrupting device” (GCB) operates. It appears that a significant emphasis of this revision is to ensure the owner of the BES interrupting device and the owner of the Protection System devices which operate the BES interrupting device are communicating and collaborating in the evaluation. It would seem that the detailed effort to ensure this provides more confusion than clarification for the GO.
Individual
Michael Falvo
Independent Electricity System Operator
No
We do not see the need to create a defined term “Composite Protection System”. By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. In the comment report, it is indicated that 4 commenters representing about 24 individuals requesting clarification of the term “composite Protection System”. This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing a new term which is redundant. We suggest to remove this defined term.
Yes
Yes
a. Applicability Section – Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs similar function when initiated by voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. b. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. “that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met”. Suggest M1 be revised to provide the performance target. c. Measure M2: Similar comment as for M1, above. The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. d. Measure M3: Similar comment as for M1, above. The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. e. Measure M4: Similar comment as for M3, above. The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after

the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. f. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. g. VSL for R3: Second condition under SEVERE - similar comment as for VSL for R1, above.
Individual
Brett Holland
Kansas City Power & Light
Yes
Yes
No
The inclusion of the following phrase is ambiguous. "….. shall perform investigative actions to determine the cause of the misoperation at least once every two full calendar quarters after the misoperation was first identified, until one of the following completes the investigation: The identification of the cause of the misoperation; or A declaration that no cause was identified." I would remove "at least once every two full calendar quarters after the misoperation was first identified." If the drafting team wants to set a time limit on the investigation, then state a not-to-exceed time period. A declaration should be available once an entity has completed all of its diagnostic tests, even if the declaration comes in the first calendar quarter after the misoperation. During the NERC webinar, one of the drafting team members indicated that the declaration could be made at any time, but I can envision a Compliance Enforcement Authority reading the language of R4 and asking why you didn't fulfill the requirement to test in the second full calendar quarter.
Yes
Group
Florida Power & Light
Mike O'Neil

Yes
No comments on the modified “Composite Protection System” definition. However, confusion may result in trying to determine whether an item fits into Misoperation Category 1 “Failure to Trip-During Fault” or into the Category 3 “Slow Trip-During Fault” definition. In both cases, the fault is likely be isolated by remote backup protection schemes. Consider combining Categories 1 and 3. Also, regarding Category 6 “Unnecessary Trip-Other that Fault,” the included wording is somewhat confusing. Consider revising to: “Spurious operation of a protection system in the absence of a fault condition on the power system it is designed to protect.”
Yes
Yes
Yes
The examples are an excellent idea. It would also be advantageous and practical to include supporting information on the scope of Misoperation reporting. Example to consider adding: The boundary of Misoperation reporting extends from protective relay input devices to circuit breaker trip coil(s). More examples should be provided in relation to Power Generation events.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (“PPL”): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: The definition for ‘Slow Trips’ has been improved in the current draft of PRC-004-3, but still requires some revision. The first means by which slow tripping can be manifested, instability, is believed to pertain only to Transmission Systems. The second effect of slow tripping, bringing backup relays into play, does not pertain to generation plants. That is, opening the breaker via a backup relay of a generation plant means not that the primary device acted slowly, but that it did not function at all. This would be a Failure-to-Trip type of Misoperation of the primary relay. We understand that variation-of-tripping is an issue of great importance for Transmission Owners (TOs), but it does not apply for generation plants (such as in the case of high speed tripping to limit system instability). Generator Owners (GOs) additionally do not necessarily have the installed equipment needed to analyze trip speed. Generation plants are not

presently required to have high-speed disturbance monitoring equipment, and many plants still have electromechanical relays (i.e. no oscillograph function). Also, GOs often lack the design-level protection relay staff necessary to perform the activities described on pp. 23-24 of the Application Guidelines.
No
The expression, “identify whether its Protection System component(s) caused a Misoperation when,” in R1 should be changed to, “identify whether (a) its Protection System component(s) caused a Misoperation, (b) functioned correctly or (c) a Misoperation cannot be ruled-out, when.” NERC acknowledges in R4 that many months or even more than a year may be needed to authoritatively classify a relay operation, and this possibility is noted also in R2.2, but R1 requires passing Misoperation-vs.-no Misoperation determination within 120 days. It was stated in the 2/20/2014 Protection Systems Misoperation Webinar that such situations should be addressed by initially assuming a Misoperation, and later ask that the coding be changed if this proves not to be the case. The PPL NERC Registered Affiliates submit (per the guidelines issued by RFC) that in the absence of evidence, a Misoperation should not be assumed.
No
The expression, “or that decided a Misoperation cannot be ruled-out,” should be added in R4 after, “has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3,” per the rationale in our comment above for R1. The outcomes listed under R4 should be expanded as shown below; since, if there are Misoperations for which no cause can ever be identified, there can also be possible-Misoperations for which a yes-or-no determination can never be made. • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven
No
PPL NERC Registered Affiliates comments above for the Slow Trip portion of the Applications Guidelines. A statement should be added, “A Misoperation should not be assumed when the cause of a relay operation cannot be authoritatively established,” (reference response to question #3) The discussion of reverse power relays on pg. 26 would be clearer if it included some of the topics and points made in the 2/20/2014 Protection Systems Misoperations Webinar. We propose stating that “The control-vs.-protective demarcation of reverse power relays is based on the operation at hand and not programming”. Failure of a reverse power relay to open the breaker at the established time after commencement of motoring is not a Misoperation if using the relay to trip a unit as part of a normal stop sequence. The same failure would be a Misoperation if some unintended event caused the unit to import power. The statement on pg. 27, “The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred,” should be amended per our comments above for R4. That is, NERC has stated in R4 that determining the cause of a relay operation may take a very long time, and a Misoperation yes-or-no decision may not be possible if the cause for the

trip is not known. Correction is also needed for the flowchart on pg. 35. “A known or possible Misoperation,” should be substituted for, “the Misoperation,” at the top of pg. 29, and elsewhere that this expression is used, because undetermined cause for tripping can make a Misoperation yes-or-no decision impossible. The statement on p.29, “certain planned investigative actions may require months to schedule and complete,” should be changed to, “certain planned investigative actions may require months or even years to schedule and complete,” in recognition that generation units are intended to operate for years between planned outages and frequently must be returned to service as soon as possible in the event of a forced outage. The following statement should be added at the end of the same paragraph, “Taking equipment out of service for the sake of furthering the investigation is not required, and forced outages need not be prolonged for troubleshooting. However, planned outages should include any testing or other actions for which downtime is necessary.” The discussion on pg. 30 should include the point that a CAP must be developed within 60 days, but implementing the CAP may take much longer if requiring a downtime opportunity. An example should be included for multiple CAPs under the circumstance of extended troubleshooting, (e.g. taking action for the apparent cause of a Misoperation), developing a new theory and taking different action when the event occurs again several months later and making a final and successful corrective action when the problem occurs a third time.
The expression, “the Misoperation,” in R5 should be changed to, “a determined Misoperation,” in recognition of the fact that some events can be classified only after full investigation, as described above.
Group
Duke Energy
Michael Lowman
No
(1) Duke Energy suggests rewording Slow Trip – Other Than Fault as follows: “A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed operation for a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.” By replacing “clearing of a non-Fault” with “operation for a non-Fault”, we feel this better describes the intent of a slow trip that is not a fault.
Yes
Yes
Yes

Individual
Karen Webb
City of Tallahassee
Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
Individual
Bill Fowler
City of Tallahassee
Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
None
Individual
Scott Langston
City of Tallahassee

Yes
Yes
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
No
It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.
Individual
Christina Conway
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
No
The Extenuating Circumstances process, as outlined on page 32 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the RAI project, Oncor recommends the evaluation of an Extenuating Circumstance be removed from the back end Enforcement phase and up to the Compliance Monitoring phase where the evaluation is done within a risk and controls framework. Furthermore, Oncor recommends the Registered Entity be allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity.
Individual
David Jendras
Ameren
Yes

Yes
(1) Ameren adopts all the SERC PCS comments by reference. (2) A primary reason for our negative ballot on this draft 4 is the proposed clarification (included with SERC PCS comments) to allow a System Protection group of one company's TO, GO, and DP to document R2 and R3 notifications within its database or PRC-004 software, rather than exchange emails or Faxes.
Yes
No
(1) We request the drafting team add another example to clarify the paragraph on page 26, following Example 8b, which includes "…however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." (a) Units in our GO's fleet shut down thousands of times each year, in our opinion Example 8a are applicable. Does the SDT intend to include these as correct operations if indeed the same reverse power relay also provides anti-motoring protection? (b) Our protection scheme in some cases will have separate Device 32 elements, with one short and one longer timer; does the SDT intend in these cases that only trips by the longer timer are within PRC-004 scope? GO will need to know as either of these differ from our understanding of NERC SPCS / RAPA guidance for reporting of total operations under the presently applicable PRC-004-2a. (c) Based on the number of reverse power questions on your 2/20/2014 Webinar, it appears to us that many GO's are unclear on your intent. [Generator reverse power reporting clarity is another primary reason for our negative ballot.] (2) At the end of Example R4a on page 29, please add "Each of 3/24, 4/10, 5/27, and 8/29 actions are valid investigative actions." If the SDT intends otherwise, please state which ones are valid.
(1) Delete from R1 1.1 "or by manual intervention in response to a Protection System failure to operate;" and remove from Rationale for R1, and Process Flow Chart. This is an extremely rare occurrence not warranting special inclusion in the requirements. In our view, manual intervention is already included in that Failure to Trip is a Misoperations and a BES interrupting device did operate, albeit manually. It is acceptable to retain some mention or explanation of it in the Application Guidance to keep it from falling out of the consciousness. Unnecessary Trip – During Fault on page 24 already points out the correct remote clearing that would occur for a Fault. [Unwarranted inclusion of 'manual intervention' in a Requirement is another primary reason for our negative ballot.] (2) Please add "Note: Historically, the cause of about of 10% NERC-wide Misoperations have an unknown cause" at the end declaration paragraph (2nd last paragraph) on page 29. (3) On page 31, please add "For completion of the CAPs in examples R5a through R5d see examples R6a through R6d on pages 33 and 34." (4) We understand R1 to apply to the aggregate set of BES interrupting device operations associated with the same BES event (e.g., fault, abnormal condition, etc.) For example, under present NERC SPSC guidance the entity count all trips in the automatic reclose cycle and reports them as a single event. (5) The NERC PSMTF Final Report recommended grouping all like events involving the same Protection System within a 24

hour period, recognizing that the response time limitations to altering the Protection System. SERC PCS advocated the 24 hour grouping in our comments to NERC on the Section 1600 Data Reporting draft. The resulting metrics more clearly indicate dominant causes, rather than being distorted by repetitive like events on the same Element and Protection System. (6) If the SDT intends that each and every BES interrupting device operations be separately tracked, the TO, GO, and DP certainly need to know this. Although every breaker operation is almost always available within the SCADA log attached in our PRC-004 software database, we group them into a single event record in accordance with applicable NERC guidance. We are concerned that if R1 intends we have a separate event record for each breaker operation, the administrative overhead is unwarranted and burdensome.
Individual
John Seelke
Public Service Enterprise Group
No
We agree with the definition of Composite Protection System, but we believe that the categories definition of Misoperation could be improved. The standard does not address situations where one cannot determine whether the Protection System operated correctly or whether a Misoperation occurred. • Without evidence of a Fault associated with a trip, it is possible that Normal Clearing occurred, although there may be no evidence to support or reject that conclusion. • Without evidence of a Fault associated with a trip, it is also possible that a category 5 (Unnecessary Trip – During Fault) or category 6 (Unnecessary Trip – Other Than Fault) Misoperation occurred; however, there may be no evidence to support or reject either reporting category. In order to address a situation when the operation of a Protection System cannot be determined to be a correct operation or a Misoperation, we believe a seventh Misoperation category should be considered: “Unclassified Trip: Any trip that (a) cannot be confirmed as the correct operation of the Protection System and (b) for which the evidence is not sufficient to place the trip into another Misoperation category.” This will cause all such trips to be consistently investigated as Misoperations. We understand that many of these Misoperations may result in an undetermined cause.
Yes
No
In R4, we find the phrase “two calendar quarters” unclear since it is referenced from the date when the Misoperation was identified. For simplicity, that phrase should be replaced with “180 days.” Also, there may be a need to extend the time. For example, if an investigation required removing a transmission line from service, one may not be able to obtain a clearance to do so within 180 days, so an investigation action could not be performed, resulting is a violation of R4. Therefore, the 180 day time frame should be allowed to be extended for good cause if the owner documents the cause of an extension. Our recommendation is to replace R4 with this language: “Each Transmission Owner,

Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every 180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause), until one of the following completes the investigation:" Finally, in the "Rationale" text box, the phrase "(120 calendar days)" should be stricken since it does not apply to R3. If notice per R2 is given on day 120, the entity under R3 has 60 day time period, while if notice is given on day 1, it has a 119 day time period.
No
The Application Guide is unclear as to the reporting of reverse power relays. A reverse power relay is typically used to remove a generator from service (a control function) AND to prevent generator motoring (a protection function). The two are not separable. On p. 26, example 8a removes the operation of a generator's reverse power relay to open a breaker during routine shutdown from being subject to the standard because it is performing a control function, while the guideline then states "; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." If the reverse power relay failed to open the generator's breaker during shutdown, the generator would motor and the breaker would need to be opened by manual intervention. As the SDT may know, reverse power relays have a documented "blind spot" that causes them to fail to operate during low power factor operation of the generator. (We can provide such documentation if desired). For this reason, generator operators normally have procedures with a step that states that the operator is to manually open the generator output breaker if generator the breaker does not open after a predetermined time period. If this occurred, would the failure of the reverse power relay be reported as a Misoperation? Finally, per the NERC document "Questions and Answers about Consistent Protection System Misoperation Reporting" dated February 5, 2013, reporting a reverse power relay Misoperation and not reporting a successful operation is inconsistent with the principle stated in paragraph #1 that "if an operation would not count as a misoperation, it should not be included as an operation." Therefore, to avoid further confusion, we recommend that reverse power relays used for equipment shutdown be explicitly eliminated from the scope of this standard.
There is no requirement in the standard for the cause of a Misoperation to be determined by the appropriate Protection System owner. Neither R1 nor R3 obligates the owner to attempt to determine the cause of a Misoperation. We note that R4 presumes the owner could not "determine the cause(s) of a Misoperation in accordance with R1 and R3" when those requirements contain no such obligation. R5 and R6 apply to an owner that has determined the cause(s) of a Misoperation. Therefore, we recommend that R1 and R3 be modified as follows with the following additional capitalized language: ".... shall identify whether its Protection System component(s) caused a Misoperation OR NOT, AND IF SUCH A MISOPERATION OCCURRED, SHALL DETERMINE, IF POSSIBLE, THE CAUSE(S) OF SUCH MISOPERATION. " As R1 and R2 are written, one could interpret the language as requiring

ALL interruption device operations be evaluated. However, this is not the intent based upon the draft RSAW that's posted. It states that the evidence required in R1 is "A list of BES interrupting device operations within audit period meeting the criteria of Requirement R1 Parts 1.1 through 1.3." Therefore, we recommend that R1 and R2 be changed so that it is clear that the only interruption device operations that need to be examined are those that are the unexpected. Expected operations for, as an example, switching would be eliminated from any requirement to review the interrupting device operation. This would greatly simplify the data required to demonstrate compliance. We offer the following additional capitalized language in R1 and R2: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated UNEXPECTEDLY shall,…."
Individual
Matthew Wykstra
Consumers Energy Company
Yes
Yes
Yes
No
Generally I agree with the proposed new definition of a Misoperation, but have one hypothetical circumstance where it might be unclear and could perhaps benefit from another example in the guidelines section. Under the category "Unnecessary Trip – Other Than Fault," the guidelines state that an operation that was initiated directly by on-site maintenance…is not a Misoperation. Are there circumstances where on-site maintenance could indirectly cause a Misoperation? We had a situation where a technician was conducting testing on a breaker failure (BF) relay, and accidently initiated the wrong BF relay in an adjacent panel that was still in service and not part of the testing plan for the day, resulting in tripping of the BES bus. Our initial thoughts were that the BF relay should have issued a 'retrip' function to its corresponding breaker after being initiated, thereby only tripping the one breaker instead of the entire bus. Investigation showed the relay was indeed designed to trip the bus and acted properly. BUT if the relay HAD operated improperly after being inadvertently initiated by on-site personnel, would that be a Misoperation? Does the presence alone of on-site personnel create an exemption in all cases? If that is the case, I think it should be explicitly stated, or another example added to clarify technician-induced operations.
Individual
PHAN, Si Truc

TransEnergie Hydro-Quebec
Yes
Yes
Yes
Yes
An addition « Field» can be added to improve metric analysis of microprocessor relays malfunction since these are the type of relays that will be installed in the future by every entities. As the number of microprocessor continue to grow, the more frequent will a Misoperation be caused by these type of relays, therefore this added field would greatly improve metric analysis. For example, the Field Value for a microprocessor relay malfunction could include the following: Setting Error – Incorrect Numerical Input Specified Setting Error – Incorrect User-Programmed Custom Logic Incorrect Design – Incorrect User Application Incorrect Design – Wiring Firmware Version Mismatch by User Others
Individual
Bill Temple
Northeast Utilities
Yes
Yes
No
The term “investigative action(s)” used in Requirement 4 is somewhat ambiguous even given the examples cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. Can simply confirming an outage schedule be enough of an investigative action to satisfy all compliance auditors as suggested in the Application Guidelines?
Yes
Individual
Chris Mattson
Tacoma Power

No
In the definition of Misoperation, Unnecessary Trip – Other Than Fault, change "…caused by…" to "…related to…" In the definition of Misoperation, there may be some ambiguity/overlap in determining if some Misoperations are due to a Slow Trip or an Unnecessary Trip when Protection Systems are found not to have been adequately coordinated. It is suggested that something like the following change be made to Slow Trip – During Fault and Slow Trip – Other Than Fault: Change "…or resulted in the operation of any other Composite Protection System…" to something like "…or a Protection System component failure resulted in the operation of any other Composite Protection System…" Inadequately coordinated relay settings would then more clearly fall under either Unnecessary Trip – During Fault or Unnecessary Trip – Other Than Fault. The only other remedy would be to categorize the Misoperation based upon the corrective action taken. (It should be noted that this ambiguity/overlap is only an issue if Misoperations must later be coded during a NERC data request.) In the definition of Misoperation, Slow Trip – Other Than Fault, consider removing the reference to "…voltage or dynamic instability…" It seems that these issues may be more related to Fault conditions.
Yes
Yes
No
On page 24 of the redlined Application Guidelines, remove the following verbiage: "This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally," This portion does not add value and seems to have a conflicting emphasis with the reminder of the paragraph. Regarding Example 4 in the Application Guidelines, Slow Trip – Other Than Fault, equipment damage is not explicitly identified in the definition of a Misoperation. Either the definition should be revised to clearly identify equipment damage or another example should be used that better fits the proposed definition.
Since Protection System operations that are related to (or caused by, if this verbiage is retained) on-site maintenance, testing, inspection, construction, or commissioning activities are by definition not Misoperations, is it necessary under Requirement R1 to document that the entity identified "whether its Protection System component(s) caused a Misoperation" for these cases of Protection System operations? BES interrupting devices may be operated many times during on-site activities from a Protection System, or part of a Protection System, and it would be very burdensome to document actions taken surrounding this activity for purposes of compliance with PRC-004-3 Requirement R1. Consideration should be given to an additional part under Requirement R1 such as the following: "The BES interrupting device operation was not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities." Regarding the Severe VSL for Requirement R3, change "…whether or not a Misoperation

its…” to “…whether or not a Misoperation of its…” (This also needs to be updated in the VRF/VSL Justification.) Regarding the Moderate VSL for Requirement R5, change the two instances of “…calendar days first…” to “…calendar days of first…” (This also needs to be updated in the VRF/VSL Justification.) On page 32 of the redlined VRF/VSL Justification, in the FERC VRF G3 Discussion, change references to ‘VSL’ or ‘VSLs’ to references to ‘VRF’ or ‘VRFs’ respectively. On page 39 of the redlined VRF/VSL Justification, in the discussion of FERC VSL G1, change “…being based the…” to “…being based on the…” On page 2 of the redlined Mapping Document, in the Comments column, change “…a review upon a Bulk Electric System (BES) interrupting device operation…” to something like “…a review upon a Bulk Electric System (BES) interrupting device operation initiated by a Protection System and not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities…” Explicitly reviewing and (more to the point) documenting each BES interrupting device operation is overly burdensome, as this would include control operations, including those associated with switching, as well as operations caused during on-site activities. On pages 4 and 19 of the redlined Mapping Document, in the Comments column, change “…a reverse power relay operated to remove a generating unit from service…” to something like “…a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection…” Whether it is for a protective or control function, the reverse power relay will still remove the generating unit from service; the distinction is why the generating unit is being removed from service. On page 5 of the redlined Mapping Document, in the Comments column, change “…underfrequency load shedding (UFLS)…” to “…underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements…” The Applicability does not include UFLS that trips non-BES Elements (e.g., medium voltage distribution feeders). On page 21 of the redlined Mapping Document, in the Comments column, change “…until is…” to “…until it…”
Group
Dominion
Mike Garton
Yes
No
The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date.
Yes
No

a). During the webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples to include: 1. A gas turbine generator has a single reverse power relay which is used to trip the generator breaker during a normal controlled shutdown. This function is considered a control function and not counted as an operation or a Misoperation. 2. The reverse power relay (mentioned in example 1) does not operate to trip the generator breaker and the unit continues to motor until the operator intervenes and opens the breaker manually. Is this a Misoperation? If so what protection system misoperated? Is this considered a Misoperation due to lack of protection? 3. The gas turbine generator mentioned in example 1 and 2 also has a separate reverse power relay that directly trips the generator lockout relay. Is this function considered part of the Protection System? With the unit operating at normal load, this relay incorrectly trips the unit due to an internal relay problem. Is this a Misoperation? 4. A steam turbine generator has a reverse power relay (sometimes referred to as a Sequential trip relay) used in conjunction with valve position switches to trip the generator following a turbine trip. This function is considered a control function and not counted as an operation or a Misoperation. 5. The reverse power relay mentioned in example 4 (sometimes referred to as an Anti-motoring relay) does not operate during a turbine trip and after thirty seconds a second reverse power relay operates as designed to directly trip the generator lockout. Is this second reverse power relay considered part of the Protection System? If so is this counted as one operation that needs to be evaluated? b). Mechanical type breaker trip examples should be expanded to show that air pressure, gas pressure and pole disagreement trips (and their associated auxiliary relays) are control functions and therefore not part of the protection System and thus not subject to this standard. In addition, gas and oil type fault pressure relays on transformers are excluded from Protection System. The example should clarify whether the transformer auxiliary tripping relays (sometimes referred to as 63X relays) are part of the Protection System. Examples could be extremely helpful here since no examples are included in the definition of Protection System. c). Additional Application Guideline examples are needed and the following are specific examples that should be considered: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of its Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the highside breaker that was closed

to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 5. A 230KV line trips at one terminal via its carrier ground relay during closing of a line switch to re-network the line. There was no fault, but the relay operated during typical phase current imbalance created by the poles of the switch closing at different times. Is this a Misoperation?
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes
No
Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording to allow additional time when a utility endures a natural disaster.
Yes
The Severity Level wording (re CAP development) is too stringent and very confusing. Adding roughly 5 days (from the timeframe stated in the previous draft) is negligible. The current requirement allows 12 months for CAP development, and changing this to 120 days will not, in some cases, give a utility adequate time to investigate/determine actions going forth.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Yes

Yes
Yes
Yes
WECC Extended Implementation Period - The Standard as proposed allows entities in the WECC Region an additional 12-months to comply with the Requirements of PRC-004-3. Seminole requests that entities in all other NERC Regions have the same amount of time to comply. Correlating every Region's effective date to that of WECC would be just, reasonable, and less preferential. Evidence Retention - Bullet 2 under section C.1.2. of the Standard deals with evidence retention. Bullet 2 specifically requires retention of evidence 12 months from the date of "completion of each CAP, evaluation, and declaration." It does not appear that Requirement R5 covers the completion of the CAP; it appears that specific requirement is covered in Requirement R6 and bullet #3 of the evidence retention section. Seminole reasons that the drafting team meant Bullet 2 to state that the retention period is from the date of completion of the "development" of a CAP, not the completion of remedies stated in a CAP. In addition, there are three possible dates for completion of a CAP, evaluation, and declaration. Seminole requests that the drafting team clarify which date, and time period, specific evidence is required.
Individual
Steven Mavis
Southern California Edison Company
No
There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry.
No
There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry.
Group
Southern Company: Southern Company Service, Inc.; Alabama Power Company; GeorgiaPower Company; Gulf Power Company; Mississippi Power Company; Southern CompanyGeneration; Southern Company Generation and Energy Marketing
Wayne Johnson

Yes
Yes, provided that it is made plain that, for the purposes of reportability, the failure or misoperation of an individual component of the Composite Protection System is not to be considered a reportable Misoperation when the Composite Protection System taken collectively functionally did not misoperate. Without this clarification, it is still confusing to state that the failure (misoperation) of an individual component of a Composite Protection System is not a misoperation. We suggest adding "reportable" to all occurances of the phrase "is not a misoperation" to read "is not a reportable Misoperation" where the phrase occurs in the draft standard (12 occurances). The definition of Misoperation, items 5 and 6 need to have the word Composite inserted between unnecessary and Protection
Yes
If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.
Yes
On page 28 of the clean draft #4, in the first sentence of the R4 section, the words "the entity" appearing after the comma are redundant and are not needed.
Yes
1. The removal from R1 of the qualifier of an operation ‘device operation caused by a Protection System operation’ has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device comes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. The added change of including ‘or by manual intervention in response to a Protection System failure to operate’ additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each TOP and GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. Note: related to above 3 comments: Although the recently posted RSAW mitigates some of these concerns, we feel

the Standard itself should be modified to go back to the concept of ‘BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation’ thus removing the need to include the TOP in the applicability. 3. The various timetables introduced in the Standard result in many compliance milestones to be tracked for minimal if any overall increase in reliability. There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. 4. We also observe that the Standard does not require any closure on a specific event. As noted in R6: implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. Therefore, an acceptable CAP could be ‘we plan on upgrading the protection systems in 15 years which will solve the problem’. Since the neither proposed actions nor timetable may change, no update is required. This seems to contradict the statement in the Rational box for R6 which states: Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion. 5. Related to comment#4 above, which notes that there is no requirement for closure: Recognizing that there has been considerable work by various NERC teams (SPCS, RAPA, and the PSMTF) to implement consistent reporting utilizing the misoperation template and that one of the recommendation was that the Regional entities need to become closely engaged in reviewing submittals and following up on action plans/ corrective actions; we would encourage the SDT to consider revamping the Standard to require the quarterly submittal of misoperation data utilizing the approved template and NERC and the Regions to agree on some standard methodology for Regional review and follow-up if progress is not being made.
Group
ACES Standards Collaborators
Jason Marshall
Yes
The definition of Misoperation is much improved. We thank the drafting team for proposing a definition for Composite Protection System. It adds clarity to the standard.
Yes
(1) While we agree the revisions to these requirements clarify what is required, we feel that R2 meets P81 criteria. First, R2 meets P81 criterion A because the requirement of notifying another owner does little to support reliability. Second, R2 meets P81 criterion B1 because it is clearly administrative, and it meets P81 criterion B4 because it requires reporting to another party. Without significant justification for how this administrative, reporting requirement materially and substantially supports reliability, we cannot support it. We suggest that requirement R2 should be removed and an explanation of the desired reporting would be appropriate in the Application Guidelines. The Application Guidelines on page 28 in the first paragraph acknowledges that “notifying the other owners… may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability.” (2) If Requirement R2 persists, we cannot support a medium VRF

for R2. This requirement simply does not rise to the level of having an "impact on the electric state or capability of the bulk electric system" which is what is required to meet the Medium VRF criteria. The requirement is an administrative requirement and does not have any impact on the electric state or capability. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the applicability section. By definition, the Distribution Provider cannot own a "BES interrupting device" since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. If they are not, then NERC/regional entity has made a determination per Note 1 in the statement of compliance registry criteria that the BES interrupting device does not have a material impact on the reliability of the bulk electric system and has not registered them. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the requirement to apply to the Distribution Provider. (4) Requirement R3 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the responsible entity "to identify whether its Protection System component(s) caused a Misoperation." If a responsible entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown.
No
(1) This requirement should be modified to simply state that the applicable entity is required to identify the cause of the Misoperation or document that a cause could not be found. It is too prescriptive that an applicable entity must identify investigative actions each successive two calendar quarters. This makes the requirement inflexible and needs to be simplified. Consider an example where an applicable entity that should be performing more investigative actions every two successive calendar quarters can be compliant by simply identifying one and an applicable entity in a unique situation that cannot perform even a single investigative action in the two successive calendar quarters due to extenuating circumstances would be in technical non-compliance. (2) This requirement incorrectly implies that R1 and R3 require the applicable entity to identify the cause of the Misoperation. They do not. Rather, R1 and R3 simply require the applicable entity to identify Misoperations. Thus, R4 should be modified to simply require identification of the cause of the Misoperation subject to reasonable investigative actives or declaration that the cause could not be identified after completing reasonable investigative actions.
Yes

The examples in the Application Guidelines are improved and provide additional clarity.
(1) We are concerned that Part 1.1 may cause an auditor to request an inventory of all BES interrupting device operations. From that list, then the applicable entity would be required to identify which BES interrupting device operations were cause by Protection System actuation and which were operator interventions. Then, the applicable entity may have to prove each BES interrupting device operation initiated by an operator was not necessitated by a Protection System Misoperation. Also, the applicable entity would have to show for each BES interrupting device operation caused by Protection System actuation was evaluated for Protection System Misoperation. While we understand that an applicable entity will have to show it evaluated each BES interrupting device operation caused by a Protection System operation, we do not believe they should be required to identify those operations caused by other means such as a manual operation by the operator. To identify cases where manual intervention was necessary due to a Protection System misoperation, the applicable entity should be able to rely on its operator notifying the protection systems department that such actions were necessary. In other words, Part 1.1 should be evaluated based on this exception with the auditor only requesting the applicable entity to identify the instances where manual intervention was necessary. An explanation in the Application Guidelines for what is required here would be helpful. (2) Requirement R1 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the entity “to identify whether its Protection System component(s) caused a Misoperation.” If an entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the requirement. By definition, the Distribution Provider cannot own a “BES interrupting device” since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the Distribution Provider to apply. (4) For the second severe VSL of R3, “a Misoperation its Protection System” should be “a Misoperation in its Protection System.” The “in” is missing. (5) We disagree with the VRFs for R2. It is an administrative requirement and should not even be a requirement since it meets P81 criteria. However, if the requirement persists, the VRF should be no higher than “Low” since it is administrative. (6) Thank you for the opportunity to comment.
Group

Florida Municipal Power Agency
Frank Gaffney
No
FMPA appreciates the response to our comments, but, we do not believe our issues from our past comments have been resolved. Regarding “Slow Trip”: FMPA agrees in concept with providing the ability to apply engineering judgment regarding what tripping “slower than required” may mean but believes there is too much ambiguity. We agree that “It is impractical to provide a precise tolerance ...”; however, If the standard is kept in this format, we support a clarification on the order of “fast enough to prevent harm to the protected equipment, undesired overtripping, or harm to stability.” FMPA believes “BES interrupting device” should be a defined term because it now drives the majority of the compliance activities associated with the standard. Specifically we believe with the way this device is characterized in the Application Guide is deficient. Devices that do not have “fault current interrupting capability” but have load interrupting capability, are often also used for protection functions in “Other than Fault” scenarios. Also, we note that fuses do not qualify as Protection System components although they meet Application Guide description of “BES interrupting device”. Confusion concerning treatment of fuses and the definition of BES Interrupting Device could lead to unintended consequences, such as a proliferation of use of fuses. FMPA still believes that the remaining definitions – Failure to Trip (During and Other than Fault) and Unnecessary Trip (During and Other than Fault) have similar difficulties to “Slow Trip”, wherein the standard provides the leeway for entities to apply judgment but that same leeway affords no way of supporting such judgment with evidence if an auditor disagrees with the interpretation. FMPA also believes that specifically excluding remote backup devices from the definition of Composite Protection System wrongly places a negative connotation on those typically lower voltage (100 – 161 kV) systems in which remote backup for a relay or breaker failure is “as-designed”. We recognize that under the current format it will be difficult to avoid this issue – however if entities were able to develop their own Protection System Design Philosophy documents with this issue specifically addressed (see response to question 5 for more description of this proposed approach) as the criteria against which performance is measured, this problem goes away.
No
FMPA believes there are still ambiguities regarding the responsibility where to or more entities share ownership of a Protection System. Specifically as R1 relates to R2 the language reads in a way that seems to imply entities are required to wait to provide notification of the ongoing investigation to one another, which we believe is not the intent. Furthermore please clarify; where BES interrupting devices are associated with multiple Composite Protection Systems; Does 1.2 refer to the Composite Protection System which is believed to have operated or to all Composite Protection Systems associated with the BES Interrupting device (which may or may not be owned by the same entity)?
No

FMPA believes it would be beneficial to actually lay out specific failures in the examples. For example, “Slow Trip – During Fault” simply says “A failure of a line’s Composite Protection System to operate as quickly as intended for a line fault is a Misoperation.” This is more or less a restatement of the definition but applied with the additional detail of a specific protected component (the transmission line). Rather, consideration should be paid to an actual way a relay could fail – for example “…a line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay’s negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element…” most of the nuance in the application comes from the way the relay failed. Another example might be a line fault with electromechanical relays wherein the relay output contacts stuck initially, resulting in a delayed clear.
In general, FMPA disagrees with the philosophy of the current standard. Protection system design is too complex, too diverse, and requires too much engineering judgment to be conducive to making all system designs and voltage classes of systems fit into one set of criteria. Many of the comments the PSM SDT has been receiving are evidence to that effect. System Protection is just as much an art as it an engineering science (i.e., “The Art and Science of Protective Relaying”, C. Russel Mason, Wiley, 1956). FMPA supports the intent of the statements that the SDT has laid out which seek to provide the individual entities with the ability to provide engineering judgment, but there is no clear cut way to establish measures and allow entities to demonstrate compliance without a set of specific criteria against which the comparison can be made. Thus, FMPA believes entities should have “Protection System Design Philosophies” for their systems as appropriate, analogous to the FAC-008-3 and the prior FAC-008-1 and 009-1 standards and facility Rating Methodologies. Entities can lay out the characteristics of their systems – what is the “intended operation” for the systems, and what, generically, constitutes the constraints around which that entity develops its Composite Protection Systems. We recognize the tremendous amount of work the PSM SDT has put forth in attempting to reach industry consensus on this document but do not believe any form of document that applies criteria without a corresponding philosophy behind that criteria makes the standard too ambiguous. In recognition of the art of protective relaying, we suggest documenting a protection philosophy and intended operation of systems against which to measure whether a protection system operates as intended or not.
Individual
Alice Ireland
Xcel Energy
No
1) The definition for Composite Protection System could be clearer. For example, are the relays deployed at all ends of a transmission line for the protection of that line considered a part of one Composite Protection System? Does the presence or absence of a

communications-assisted scheme change which relays would comprise the Composite Protection System? 2) The definition of Composite Protection System should be modified to account for all of the elements that may or may not operate to protect an element, excluding breaker failure protection. Breaker Failure protection should be considered its own zone of protection. Suggested change as follows: The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. Breaker failure protection should be considered as protecting its own specific breaker element. 3) We have two issues driving our negative vote. The first issue is that high speed performance requirements for identified Composite Protection Systems are not defined or controlled by a single entity with regional grid performance knowledge, such as Transmission Planning. Without centralized accountability to identify performance requirements for specified systems, settings will be installed according to the PRC-001 coordinated settings implemented by the BA, and TO or GO system owners. These settings have been coordinated with the applicable entities. Transmission Planning is the entity that should be cognizant of settings required to maintain system stability under various fault conditions, and notify TO system owners of these requirements for inclusion in PRC-001 coordination. This coordination needs to be identified, tracked, and proper timelines for implementation identified. 4) The second issue driving our negative vote is the lack of a time requirement tied to when a "previously identified" high-speed performance need has to be implemented. For example, under the Slow Trip – During Fault, the phrase " …if high-speed performance was previously identified…" has no time horizon to make this an effective requirement. If a high speed, 3 cycle fault clearing requirement was identified by e-mail the previous day, and the device was not reset immediately, and a subsequent event caused the device to operate at 30 cycles, a Misoperation would result. Instead, a process by which requirements are identified by the planner, allowing an defined period for implementation, should be required. This could be accomplished by either adding Transmission Planning as an applicable entity with notification requirements defined in the requirement language, or including the GO/TO/Distribution provider as a partner in this process in another standard, such as PRC-001 or the TPL series. Proposed rewording is as follows : Misoperation: The failure of a Composite Protection System to operate as intended and previously coordinated. Any of the following is a Misoperation: Slow Trip – During Fault – A Composite Protection System operation that is slower than for a Fault condition for which it is designed and coordinated. Delayed clearing of a Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. Slow Trip – Other Than Fault – A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed and coordinated, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. And similar edits to all other fault definitions in the document, removing the "…previously identified…" language.
No

1) There appears to be a potential gap if a Composite Protection System wholly owned by one entity experiences a Failure to Trip, and only interrupting devices wholly owned by another entity operate. 2) Propose wording change for R1 through R3 as follows: “R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Associated Composite Protection System component(s) Misoperated when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”; “R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the Associated Composite Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”; and “R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Associated Composite Protection System component(s) caused a Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]”
Yes
No
1) The examples for R6 in the Application Guidelines are not clear. In R6a, it states the CAP completed on 6/25/2014, but no action is referenced for this date. In R6b, it states the CAP completed on 10/28/2014 when a proactive only replacement program was established, but in R6c and R6d, the CAP is open until the proactive replacement program is completed. It seems the difference between these two is only semantic. 2) Please clarify if it was the intent of the drafting team to exclude operations like the following example from being classified as a Misoperation: Assume that a fault occurs in a generator stator, due to either a mechanical or design setting issue the 64S does not operate. However, the 87 does operate and trips the unit. We believe this would not be a Misoperation because of the overall performance of the composite protection system.
Definition for Unnecessary Trip – Other Than Fault: The first sentence of this is unclear (triple-negative) without the expanded language in the Application Guidelines section. Consider omitting the clause “…for which it is not designed” to make this more clear. The analysis of a Failure to Trip situation does not appear to be covered here, except to the extent that another interrupting device trips in a different zone to prevent the event from propagating.
Group
Santee Cooper
S. Tom Abrams
Agree
Santee Cooper agrees with the SERC PCS Comments.

Individual
Texas Reliability Entity
Texas Reliability Entity
No
Texas RE is concerned that the revised definition of Misoperation is limited to failure of a Composite Protection System, and that this standard does not require investigation and mitigation of all Protection System operations/failures to operate when they are sub-parts of a Composite Protection System. We submit that any failure to operate as designed should be investigated and mitigated, even if another part of the Composite Protection System covered for the malfunctioning component/system.
No
There are several cases in the ERCOT Region where Company A owns the interrupting device and Company B owns the Protection System. In these cases, subpart 1.2 for R1 and subpart 2.1 for R2 do not apply. The language for Requirements R1 and R2 is written such that all of the subparts (1.1, 1.2, and 1.3 for R1 and 2.1, 2.2, and 2.3 for R2) must apply for the entity to initiate the analysis of the operation or notification. We would suggest modifying the language for R1 and R2 to say that the Requirement applies if one or more of the subparts apply.
No
There should be an end time frame for this requirement. If an entity has not determined if a Misoperation occurred within 120 days of the interrupting device operation, they could conceivably continue to investigate the event for years, as long as they perform an investigative action at least once every 6 months.
(1) For Requirement R5, how does the SDT intend to handle a situation where the CAP involves another registered entity. For example, we've seen several cases where the CAP requires multiple TOs to make setting changes in order to mitigate the cause of the misoperation. In this case, should both TOs involved have their own CAP? The requirement language is not clear. The bullet "Explain in a declaration why corrective actions are beyond the entity's control…" provides no assurance that all the required actions to mitigate the Misoperation are completed in cases where multiple entities are involved in the CAP. (2) Evidence Retention: We recommend changing the evidence retention from 12 months to a minimum of 3 years.
Group
DTE Electric
Kathleen Black
Agree
RFC Protection Subcommittee
Individual

John Brockhan
CenterPoint Energy Houston Electric LLC
No
CenterPoint Energy agrees with the new definition for Composite Protection System and believes it is needed to support consistent misoperations reporting. However, we suggest additional clarifications for the two Slow Trip categories of Misoperation definitions that were revised to address high-speed performance. The second sentence of the two Slow Trip categories of Misoperation definitions states: ‘Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System’. We recommended changing this sentence to state the following: ‘If the Composite Protection System is comprised of two, or more, independent high-speed schemes, delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or if high-speed performance was previously identified as being necessary for coordination with other Composite Protection Systems.’
No
CenterPoint Energy believes a requirement to perform investigative actions to determine the cause of a Misoperation at least once every two full calendar quarters after the Misoperation was first identified will result in repetitious investigative actions and scheduled outages and would provide little benefit. Also, we do not believe a declaration is needed, since assigning a cause code of Unknown / Unexplainable is part of the misoperation analysis process. The Cause Code and an explanation of the exhaustive investigation and tests conducted should be sufficient. Therefore, we recommend Requirement R4 be deleted.
CenterPoint Energy recommends revising the wording of the second bullet of Requirement R5 to account for situations where corrective action would not be practical. CenterPoint Energy suggests the following wording: ‘Explain in a statement why corrective actions are beyond the entity’s control or would not improve BES reliability or may not be practical, and that no further corrective actions will be taken.’
Individual
Roger Dufresne
Hydro-Québec Production
Yes
No

For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system . For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation.
Yes
No
For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system . For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation.
The purpose of the Standard shall be limited only to "Identify and correct the causes of Protection System Misoperations affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC.
Individual
Scott Berry
Indiana Municipal Power Agency
No
We see no alternative other than to install SOE equipment and/or Disturbance Monitoring Equipment and/or Digital Fault Recorders to monitor the Composite Protection System during operations/Misoperations of BES interrupting devices. With the current definition of Misoperation, especially the Slow Trip definitions, it will be crucial to the investigation to have exact Protection System parameters and operation times prior to, during, and immediately following any operation on a BES interrupting device. In short any Protection System element (any device subject to PRC-005) must now be logged, recorded, and archived in order for a Registered Entity to be able to go back and show that their Protection System/Composite Protection System operated as designed and did not contribute to a Misoperation on either their own BES interrupting device and/or an adjacent Registered Entity’s BES interrupting device. This will be a considerable expense for smaller GOP’s and DP’s to install, operate, and maintain the equipment and archive the data and records required to meet the burden of these proposed definitions.
No

It is not clear how an entity is to show that an operation of a BES interrupting device happened fast enough and did not fall into one of the two "Slow Trip" categories of a misoperation.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
We believe that the term “local backup” includes breaker failure relaying, but it appeared at the webinar that the drafting team does not intend for breaker failure relaying to be included in the definition of Composite Protection System. We recommend that “local backup” be removed from the definition or changed to “local backup (excluding breaker failure protection).”
No
We generally agree but we have some concerns about multiple entity ownership of different Protection System components compared to joint ownership of individual components.
Yes
Yes
1. The standard is difficult to interpret regarding jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. An interrupting device and all or part of the Composite Protection System may be owned by a contractually-organized group that is not a registered Functional Entity. This makes it unclear which entity is responsible for initial review and potential notification under Requirement R1. Our belief is that it would be the registered entity that is contractually responsible for operating the interrupting device. 2. It is also unclear whether Requirement R2 includes notice to all the other joint-owners of the Protection System or only to the owners of the Protection System components that are not owned by the joint group. Our belief is that notice should only be given to the owners of the Protection System components that are not owned by the joint group. Our proposal to eliminate the uncertainty is to add a statement to the Applicability that addresses how jointly-owned Facilities are to be handled in the standard any time a TO, GO, or DP has a responsibility.
Group
ReliabilityFirst Protection Subcommittee
Bill Crossland
Yes

Yes
There was some confusion on who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion.
No
The direction included in R4 is awkwardly worded. Consider rewording the following “shall perform investigative action(s)… at least once every two full calendar quarters” AS “shall, on a semi-annual basis, continue to show evidence of investigation…”. However, the examples in the Application Guidelines are clear as to what the SDT is looking for.
Yes
Other than our suggestion from Question 2, our group would like to state that the concept of the Application Guideline is an excellent tool to retain the thought process behind the development of the standard. Its use in this and future standards will help greatly with the understanding, application, and consistency of the standards.
We believe that the rationale boxes within the standard should be retained to lend additional clarity to the requirements of the standard.
Group
SPP Standards Review Group
Robert Rhodes
No
With the introduction of the term Composite Protection System, and especially considering the movement from Composite Protection System to Protection System in Requirements R1 and R2, additional confusion may have been incorporated into the standard than existed previously. If there is a way to eliminate the movement from one term to the other or develop a clearer transition from one to the other, it would be helpful to the industry.
Yes
Yes
No
Our preference would be that during a condition of a high number of outages, such as a hurricane or ice storm, we be allowed to request a formal "state of extenuating circumstances" and extend our deadline from 120 days to 270 days. We object to the proposed process where extenuating circumstances can force a utility into a violation and then rely on a nebulous, subjective review to determine whether penalties will be imposed. See additional comments on the Applications Guides contained in Question 5 below.

Exclusions for SPS and RAS are mentioned in the Rationale Box for Applicability. If these exclusions are not incorporated in the RSAW, which was just recently posted and we have not had a chance to review, then the exclusions should be included in the applicability section of the standard. Typos/grammatical/editorial: In the last line of the 4th paragraph on Page 5 under the Background section, insert ‘be’ between ‘to’ and ‘independent’. Insert ‘of’ in both portions of the Moderate VSL of R5 between ‘days’ and ‘first’. Application Guidelines In the definition of Composite Protection System on page 21, change the ‘a’ in front of ‘Element’ to an ‘an’. In the 1st paragraph under Requirement R1 on Page 27, delete the ‘that’ following ‘identified’ in the next to last line of the paragraph. In Example R2a under Requirement R2 on Page 28, set the phrase ‘or DCB relaying’ off with commas. In the last line of the last paragraph under Requirement R3, insert an ‘as’ between ‘such’ and ‘an’. In the 2nd line of the 1st paragraph under Requirement R4 on Page 28, delete ‘the entity’ following ‘notified,’ in the 2nd line. It would be helpful to include the initiating event in Examples R4b and R4c. Hyphenate ‘in-service’ in the 3rd line of Example R4c on Page 30. In the 1st paragraph under Requirement R5 on Page 30, delete the ‘or’ and place parentheses around CAP in the 2nd line. Reword the 1st line of the 3rd paragraph under Requirement R5 on page 30 to read: ‘The time periods within Requirements R1, R3 and R5 are distinct…’ On Page 31 in the introductory paragraph for Examples R5a, R5b and R5c, insert ‘in the relay’ in the 2nd line of the paragraph following ‘capacitor’. Also, in the examples, rewrite the sentence that states ‘Replace capacitor.’ to say ‘Replace the capacitor.’ We suggest the introductory paragraph for Examples R5g, R5h and R5i on Page 32 be rewritten to state: The following are examples of a declaration why corrective actions would not improve BES reliability.’ In Example R5i on Page 32, spell out POTT. In Examples R6a, R6b and R6c on Pages 33 and 34, change the sentence in the 2nd line of both examples from ‘The failed capacitor…’ to ‘A failed capacitor…’ Delete the semicolon in the 2nd line of the last paragraph on Page 33. To eliminate any possible confusion, change the CAP completion date in Example R6c from 03/09/2015 to 03/01/2015. The example gets messy if the completion date is actually after the scheduled completion date.
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
Yes
1. Recommend that R1.3 be simplified by rewording to indicate that “The BES interrupting device owner identified that its Protection System component(s) caused the Misoperation.” 2. The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the Misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. 3. Please add an explanation in the R2

Application Guidelines for situations in which one group investigates for multiple registered entities. It's quite common for a single protective relay engineering group to investigate for the TO, GO, and DP that their company owns. We suggest the following note "(Note: In cases where a single group performs an overall investigation for several entities each with some ownership of the Composite Protection System; a single document (or electronic database) is sufficient to meet the R2 and R3 notification requirements for use by both Registered Entities.)" be added to the Rational boxes for R1, R2 and R3 as well as to the Application Guidelines. This reduces the administrative overhead of having to send yourself an email just to prove that R2 and R3 are met. The important action of identifying and correcting Misoperation causes is still done and duly documented. 4. Please augment M2 with 'databases' to more clearly allow for a single group investigating on behalf of multiple entities (e.g., GO, TO, DP) to date the notification within their database. For example, CTs on a GO breaker may be part of an adjacent TO switchyard bus protection, so there are two entity owners regarding the Composite Protection System. If owned by the same corporation, one system protection group investigates on behalf of the GO and TO, and act to identify and correct Misoperation causes.
Yes
No
See #3 in question 2 above. The examples in the Application Guidelines are beneficial, the SERC PCS suggests it would be beneficial to add additional examples and add clarity to who is to report the Misoperation. Some examples are added below. During the recent webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples specific to reverse power. Also, trips should be expanded to show that air or gas system breaker trips or pole disagreement trips are not reportable operations. Additional examples are needed and the following are recommended: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of it's Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the high-side breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application

Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? 4 A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting
1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device becomes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. 3. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. 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
Russell Noble
Cowlitz PUD
Yes
Yes
Yes
Yes
Applicability section 4.2.2 includes UFLS only if it trips a BES element. We believe that UFLS inclusion in this standard should only be applicable to those single UFLS elements that can have an adverse impact to the BES. Limiting applicability to UFLS elements which trip a BES

element will not adequately address all UFLS adverse impact elements. For example, some industrial loads must be shed in a carefully planned sequence, and it may not be possible to link the UFLS trip signal to a BES element. Instead, the trip signal is received within the industrial load (plant) whereby a controlled plant shutdown is automatically initiated. This load shedding can exceed 200 MW, and is significant. In such UFLS schemes, the actual process of the load shed within a non-BES plant should not be subject to standard compliance; however, the misoperation of the associated UFLS relay as a single point of failure should be considered as a significant BES support device. Inclusion of UFLS in this Standard may be duplicative of PRC-006-1, requirements R11, R12, and R13. An underfrequency event is generally a system wide event; conversely, the objective of Protection System action is to isolate an event to prevent it from becoming a system wide impact. UFLS elements must work as a coordinated system which can withstand several UFLS element failures, yet successfully stabilize the BES. Since PRC-004-3 addresses discovery of problems after an event, we propose that at best this Standard would assure UFLS element Unnecessary Trip misoperations would be mitigated. The discovery of a UFLS element Failure to Trip which has an adverse impact on the ability of the UFLS system to stabilize the BES as stated above is addressed by PRC-006-1. Notwithstanding the above, we do not see our concerns as requiring a negative ballot.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC PCS
Individual
Michael Moltane
ITC
Yes
Yes
ITC Holdings is concerned with the documentation requirements to track communications between the BES interrupting device owner and the protection system owner. An auditor may become more interested in communication dates being more important to them than identifying the cause of the misoperation and implementation of the corrective action plan.
Yes
Yes
Individual

Daniel Duff
Liberty Electric Power LLC
No
The maintenance exclusion should include failure to trip as well as trip. Take for example a deliberate roll of a lock out relay as a unit comes offline to test the system. Under the definition if the test caused an early trip it would not be an misoperation. But it is unclear if a failure to trip during the test would be a misoperation.
Yes
Yes
Yes
Individual
Don Cuevas
Beaches Energy Services
Agree
FMPA - Florida Municipal Power Agency
Individual
Steve Lancaster
Beaches Energy Services
Agree

Consideration of Comments

Project 2010-05.1 Protection System (Misoperations)

The Project 2010-05.1 Protection System Misoperation Standard Drafting Team ("drafting team") thanks all commenters who submitted comments on the proposed Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction. This standard was posted for a 45-day formal and public comment period from January 17, 2014 through March 11, 2014. Stakeholders were asked to provide comment on the standard and associated documents through a special electronic comment form. There were 63 sets of comments, including comments from approximately 173 different people from approximately 99 companies representing 9 of the 10 industry segments as shown in the table on the following pages.

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 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Background Information

The fourth draft of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard was posted for a 45-day formal comment period from January 17 – March 11, 2014 with an additional ballot in the last ten days of the comment period according to the new Standards Process Manual, June 26, 2013. Stakeholders from approximately 99 companies representing nine of ten industry segments provided comment. The Protection System Misoperation Standard Drafting Team (PSMSDT or SDT) has responded to all commenters and developed a fifth draft of the standard based on stakeholder comment. Changes to the standard include, but are not limited to following areas.

Summary of Changes

The PSMSDT made two substantive revisions to the previous draft 4 following the additional 45-day formal comment period of the standard and additional ballot which received 62.63% stakeholder approval. The following narrative is a summary of the two substantive revisions and other minor revisions made to the proposed draft 5 of the standard.

Definitions

The definition of "Composite Protection System" was revised for clarity. The first substantive revision is the definition of "Misoperation" concerning the two categories of "Slow Trip – During Fault." The

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

revision removes the "a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability" and uses the more clear "…if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System." The last category of "Unnecessary Trip – Other Than Fault" was revised slightly to clarify that a Protection System operation caused by on-site personnel is not a Misoperation and the SDT made other corresponding revisions to insert word "Composite" before "Protection System" for consistency with the proposed definition of "Composite Protection System."

Purpose Statement
No revisions.

Facilities
An exclusion for Remedial Action Schemes (RAS) and Special Protection System (SPS) has been provided to increase clarity that these Protection Systems are not applicable to the standard.

Effective Dates
The extended implementation provision of 24 calendar months previously provided to entities in the Western Electric Coordinating Council (WECC) Region was eliminated. The provision was originally proposed due to a perceived conflict that is no longer valid. The effective date language was inserted into Section 6 of the standard for completeness.

Requirement R1
The SDT made a non-substantive revision to more clearly describe that the BES interrupting device operation that meets the three sub-parts (i.e., 1.1, 1.2, and 1.3) must all be true to have a Protection System operation that is reviewable for Misoperation.

Requirement R2
The requirement is the second substantive revision to address a gap in performance identified through continued review during the formal comment period. The previous draft did not have a provision for the responsible entity to initiate a reliability activity under the standard in the case of a Protection System failure to operate a BES interrupting device which is what initiates the activity to review for Misoperation.

The SDT determined that a failed Protection System would cause backup protection to operate other BES interrupting devices; therefore, it is practical to have the responsible entity that provided backup protection to notify the other entity of the potential failure. It is the notification that eliminates the gap and causes the other entity to review the Protection System for Misoperation under the next Requirement, R3.

Requirement R3
Minor word change.

Requirement R4

Minor clarity revision by adding “for a Misoperation” to more clearly reference the Misoperation identified in either Requirement R1 or R3.

Requirement R5

No change.

Requirement R6

No change.

Measures M1-M6

Each of the six Measures were updated to provide the entity that is required to demonstrate compliance, what is demonstrated, and the reference to the corresponding Requirement. Revisions were based on stakeholder comment and to be consistent with drafting team guidance for developing Measures.

Compliance

The SDT clarified for Requirement R5 that evidence retention relates to the “development” of the Corrective Action Plan (CAP), each evaluation, and each declaration.

VRFs and VSLs

The drafting team made a couple of minor typographical corrections identified by stakeholders.

Application Guidelines

The SDT made a significant number of additions and clarifications to address stakeholder comment. Most notably in the section discussing the definition of Composite Protection System.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory, or other Government Entities

10 —Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
4.	Sylvain Clermont	Hydro-Québec TransÉnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2

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

13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Québec TransÉnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Abouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Dianne Gordon	Puget Sound Energy	X		X		X					

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Erika Doot	US Bureau of Reclamation	X				X					

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

No Additional Responses

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Joseph DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6

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

2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbor	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Utilities District	MRO	1, 3, 5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp.	RFC	1
2.	Cindy Stewart	FirstEnergy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6
6.	Brians Orians	FirstEnergy Solutions	RFC	NA
7.	Richard Hoag	FirstEnergy Corp.	RFC	NA
8.	Marissa Mclean	FirstEnergy Delivery	RFC	NA

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Mike O'Neil	Florida Power & Light	X									

No Additional Responses

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliate	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	SERC	1, 3, 5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	RFC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6

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

4. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3
5. Tom Owens	Virginia Electric and Power Company	SERC	1, 3
6. Rick Purdy	Virginia Electric and Power Company	SERC	1, 3
7. Chip Humphrey	Dominion Power Generation	SERC	5
8. Jeff Bailey	Dominion Nuclear	SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Marjorie Parsons		SERC	6
2. David Thompson		SERC	5
3. DeWayne Scott		SERC	1
4. Ian Grant		SERC	3
5. Ryland Revelle		SERC	1
6. Pat Caldwell		SERC	1
7. Paul Palmer		SERC	5
8. Lee Thomas		SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Jason Marshall	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

	Additional Member	Additional Organization	Region	Segment Selection
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rene Free	Santee Cooper	SERC	1, 3, 5, 6
2.	Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6
3.	Bridget Coffman	Santee Cooper	SERC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Kathleen Black	DTE Electric			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kent Kujala	NERC Compliance	RFC	3
2.	Daniel Herring	NERC Training & Standards Development	RFC	4
3.	Mark Stefaniak	Merchant Operations	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Bill Crossland	ReliabilityFirst Protection Subcommittee										X

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Tex	PECO Energy	RFC	1
2.	Larry Rogers	Vectren	RFC	1
3.	Kathy West	Dayton Power & Light	RFC	1
4.	Michael Francis	American Transmission Co.	RFC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19. Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Daniels	American Electric Power	SPP	1, 3, 4, 5
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Stephen McGie	City of Coffeyville	SPP	NA
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3
10.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
11.	Angela Summer	Southwestern Power Administration	SPP	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20. Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Warren	Big Rivers electric		
2.	Paul Nauert	Ameren		
3.	Rick Otte	EKPC		
4.	Bridget Coffman	Santee Cooper		
5.	David Greene	SERC RRO		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
21.	Individual	William H. Chambliss, Member, Operating Committee	Virginia State Corporation Commisison										
22.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration, L.P./Occidental Chemical Corporation					X					
23.	Individual	Anthony Jablonski	ReliabilityFirst										X
24.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
25.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
26.	Individual	David Kiguel	David Kiguel								X		
27.	Individual	Catherine Wesley	PJM Interconnection		X								
28.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
29.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
30.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
31.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
32.	Individual	Martyn Turner	LCRA Transmission Services Corp	X									
33.	Individual	Oliver Burke	Entergy Services, Inc.	X									
34.	Individual	Jonathan Meyer	Idaho Power Company	X									
35.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
37.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
38.	Individual	Michael Falvo	Independent Electricity System Operator		X								
39.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
40.	Individual	Karen Webb	City of Tallahassee					X					
41.	Individual	Bill Fowler	City of Tallahassee			X							
42.	Individual	Scott Langston	City of Tallahassee	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Christina Conway	Oncor Electric Delivery Company LLC	X									
44.	Individual	David Jendras	Ameren	X		X		X	X				
45.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
46.	Individual	Matthew Wykstra	Consumers Energy Company			X	X	X					
47.	Individual	PHAN, Si Truc	TransÉnergie Hydro-Québec	X									
48.	Individual	Bill Temple	Northeast Utilities	X									
49.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
50.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
51.	Individual	Steven Mavis	Southern California Edison Company	X		X		X	X				
52.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
53.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
54.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X									
55.	Individual	Roger Dufresne	Hydro-Québec Production					X					
56.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
59.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
60.	Individual	Michael Moltane	ITC	X									
61.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
62.	Individual	Don Cuevas	Beaches Energy Services	X									
63.	Individual	Steve Lancaster	Beaches Energy Services	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates the entities below supporting the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the standard drafting team (SDT). This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	Santee Cooper agrees with the SERC PCS Comments.
DTE Electric	Agree	RFC Protection Subcommittee
South Carolina Electric and Gas	Agree	SERC PCS
Beaches Energy Services	Agree	FMPA - Florida Municipal Power Agency

1. **Based on stakeholder input, the drafting team created a new definition for Composite Protection System to support the definition of Misoperation. The Slow Trip categories of Misoperation were also clarified. Do you agree with the new and revised definitions? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 56 commenters responded to this question about the proposed definitions. More than half agreed with the proposed changes. The majority of commenters responding "no" to the question had concerns that the SDT addressed through either a revision to the definition or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

There were three majority comment "themes" for this question that resulted in a change. Approximately 15 comments, supported by 43 individuals, had concerns about how to evaluate a "Slow Trip" with regard to the definition of "Misoperation." The SDT modified both "Slow Trip" categories of the definition for clarity. For example, "[a] Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System" would be a "Slow Trip" Misoperation. Second, about nine comments supported by 16 individuals either requested clarification to the definition of "Composite Protection System" and to clarify or add examples to the Application Guidelines concerning the definition. The SDT revised the definition of "Composite Protection System" and added several examples to the Application Guidelines. The last majority theme of comments from five individuals had general questions about the definitions of "Composite Protection System" and "Misoperation." Some questions raised by commenters resulted in a clarification to the definitions and Application Guidelines.

There were no majority comment themes that did not result in a change; however, there were five minority themes in the comments which did not result in a change and a number of other minority comments not summarized here. There were approximately two comments supported by 12 individuals that requested clarity in the use of "Composite Protection System" and "Protection System" in the Requirements. The SDT provided insight in the individual responses below which describe why or why not such changes improve clarity. One comment supported by eight individuals wanted to have an exclusion for dispersed generation resources (DGR) in the standard's Applicability. The SDT provide detail in the individual response that the DGR drafting team would address such an exclusion once this standard reaches industry approval. There were a number of questions about data reporting in one comment. Data reporting is being addressed in a "data request" consistent with the NERC Rules of Procedure, Section 1600, Request for Data or Information. This avoids having a Requirement for the reporting of Misoperations. Another comment requested the phrase "BES interrupting device" to be defined. The SDT did not define the phrase because it is widely understood by industry.

Last, there was a concern about undervoltage load shedding (UVLS) not being included in the standard. This will be addressed by the drafting team working on UVLS once this standard is approved by industry.

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	No	a) Misoperation Definition #3 (Slow Trip - During Fault) would require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. **Response:** The portion "[d]*elayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability…"* has been removed. Change made. b) Misoperation Definition #4 (Slow Trip - Other Than Fault) would also require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. c) For #2 & #4 sections of the Misoperation Definition as well as under Facilities (4.2.2) - UFLS/UVLS both should specifically be mentioned together. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. d) It should be clarified that non-fault tripping protection schemes as described in PRC-004-3 do not include RAS/SPS (and that RAS/SPS will be covered in PRC-016).

Organization	Yes or No	Question 1 Comment
		Response: Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. e) It should be clarified in PRC-004-3 that UFLS/UVLS are not specifically part of the RAS/SPS definition (even though this is spelled out in the NERC glossary). Otherwise, it all can be quite confusing. **Response:** It would be inappropriate for the team to restate what is governed by the *Glossary of Terms used in NERC Reliability Standards* which may change in the future and could potentially require modifying an industry approved standard that contains such a clarification. No change made. f) In all six parts of the Misoperation Definition, the phrase "...where tripping for protection purposes is involved" could be included for clarity. **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made.
US Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) requests that the drafting team clarify the bounds of the Composite Protection Systems definition. Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems. **Response:** The Application Guidelines section has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made.
FirstEnergy Corp	No	Composite Protection System as a new definition is unclear within the context of a Generating Unit as a BES Asset. Protection System, by definition, is already a composite of

Organization	Yes or No	Question 1 Comment
		the five identified components, as applicable. We do not understand the intent of adding the word Composite, or how it changes the current definition of a Protection System for a Generating Unit. **Response:** The Application Guidelines section has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made. The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates ("PPL"): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: The definition for 'Slow Trips' has been improved in the current draft of PRC-004-3, but still requires some revision. The first means by which slow tripping can be manifested, instability, is believed to pertain only to Transmission Systems. The second effect of slow tripping, bringing backup relays into play, does not pertain to generation plants. That is, opening the breaker via a backup relay of a generation plant means not that the primary device acted slowly, but that it did not function at all. This would be a Failure-to-Trip type of Misoperation of the primary relay. We understand that variation-of-tripping

Organization	Yes or No	Question 1 Comment
		is an issue of great importance for Transmission Owners (TOs), but it does not apply for generation plants (such as in the case of high speed tripping to limit system instability). Generator Owners (GOs) additionally do not necessarily have the installed equipment needed to analyze trip speed. Generation plants are not presently required to have high-speed disturbance monitoring equipment, and many plants still have electromechanical relays (i.e. no oscillograph function). Also, GOs often lack the design-level protection relay staff necessary to perform the activities described on pp. 23-24 of the Application Guidelines. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made.
Duke Energy	No	(1) Duke Energy suggests rewording Slow Trip - Other Than Fault as follows: “A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed operation for a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System.” By replacing “clearing of a non-Fault” with “operation for a non-Fault”, we feel this better describes the intent of a slow trip that is not a fault. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made.
Florida Municipal Power Agency	No	FMPA appreciates the response to our comments, but, we do not believe our issues from our past comments have been resolved.

Organization	Yes or No	Question 1 Comment
		Regarding “Slow Trip”: FMPA agrees in concept with providing the ability to apply engineering judgment regarding what tripping “slower than required” may mean but believes there is too much ambiguity. We agree that “It is impractical to provide a precise tolerance ...”; however, If the standard is kept in this format, we support a clarification on the order of “fast enough to prevent harm to the protected equipment, undesired overtripping, or harm to stability.” **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. FMPA believes “BES interrupting device” should be a defined term because it now drives the majority of the compliance activities associated with the standard. Specifically we believe with the way this device is characterized in the Application Guide is deficient. Devices that do not have “fault current interrupting capability” but have load interrupting capability, are often also used for protection functions in “Other than Fault” scenarios. Also, we note that fuses do not qualify as Protection System components although they meet Application Guide description of “BES interrupting device”. Confusion concerning treatment of fuses and the definition of BES Interrupting Device could lead to unintended consequences, such as a proliferation of use of fuses. **Response:** The drafting team asserts that the phrase “BES interrupting device” is widely understood by industry through both the absence of comments and the description in the Application Guidelines. No change made. FMPA still believes that the remaining definitions - Failure to Trip (During and Other than Fault) and Unnecessary Trip (During and Other than Fault) have similar difficulties to “Slow Trip”, wherein the standard provides the leeway for entities to apply judgment but that same leeway affords no way of supporting such judgment with evidence if an auditor disagrees with the interpretation.

Organization	Yes or No	Question 1 Comment
		Response: There is no criteria for judgment of accuracy within the Requirements. No change made. FMPA also believes that specifically excluding remote backup devices from the definition of Composite Protection System wrongly places a negative connotation on those typically lower voltage (100 - 161 kV) systems in which remote backup for a relay or breaker failure is “as-designed”. We recognize that under the current format it will be difficult to avoid this issue - however if entities were able to develop their own Protection System Design Philosophy documents with this issue specifically addressed (see response to question 5 for more description of this proposed approach) as the criteria against which performance is measured, this problem goes away. **Response:** The drafting team has modified the definition of “Composite Protection System” and changed the reference to backup protection from an exclusionary statement to an inclusionary statement to address this concern. Change made.
SPP Standards Review Group	No	With the introduction of the term Composite Protection System, and especially considering the movement from Composite Protection System to Protection System in Requirements R1 and R2, additional confusion may have been incorporated into the standard than existed previously. If there is a way to eliminate the movement from one term to the other or develop a clearer transition from one to the other, it would be helpful to the industry. **Response:** The text involving Protection System component(s) (i.e., R1 or R2) is to provide a more granular look at the specific entity’s protection whereas the text of Composite Protection System (i.e., Part 1.2 or 2.1) is referring to the broader condition where two or more entities jointly own a Protection System that makes up a Composite Protection System. No change made.

Organization	Yes or No	Question 1 Comment
Virginia State Corporation Commisison	No	Minor suggestion in Parts 1 and 2 "Faliure to Trip." I suggest changing the phrase "failure of a Protection System component" to "failure of any Protection System component." Although it may be a remote possibility, more than a single component may fail, while the Composite Protection System as a whole acts correctly. **Response:** The definition of Misoperation uses the singular form as only one Protection System component failure is required to be a qualifier in meeting the criteria. The term "any" is implicit in the statement. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	No	Ingleside Cogeneration, L.P. ("ICLP") agrees that the definition of "Composite Protection System" properly captures the concept proposed by the project team. It reflects an intent that a Misoperation is determined by evaluating the actual performance of the primary, secondary, and pilot systems in totality against the expected performance. Evaluations of individual schema failures are of little value when built-in redundancy takes over to protect the local system - exactly as the designers intended. **Response:** Thank you for your support of the definition. No change made. There is still discomfort with the definitions of "Slow Trip - During Fault" and "Slow Trip - Other Than Fault" - particularly in those cases where the design responsibility is out of our hands. For example, when PRC-024-1 takes effect, Generator Owners will have little control over the expected performance of voltage and frequency-responsive Protection Systems - provided the relays are set in accordance with the standard. This means that the definitions need to include a statement that any composite Protection System operation that reacts consistently with the parameters (settings) established in any other NERC standard cannot be a Misoperation. **Response:** If the operating time resulted in the operation of at least one other Element's Composite Protection System, then it's a "Slow Trip" Misoperation. If the Misoperation cause is determined to be a settings issue, then corrective action must be taken or a

Organization	Yes or No	Question 1 Comment
		declaration explaining why corrective actions are beyond the entity's control or would not improve BES reliability. No change made. Secondly, unless notified by the Transmission Planner or Planning Coordinator, ICLP will not know that the Misoperation of one of our Protection Systems will lead to BES "voltage or dynamic instability." The two definitions seem to recognize that the GO may not be in a position to be identify such critical Protection Systems, but can be read otherwise. Similar to the previous issue, we believe that as long as we correctly supply modeling data to the TP and PC in accordance with other NERC standards, the responsibility to identify susceptible Protection Systems remains with the planning entities. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
ReliabilityFirst	No	Throughout the draft standard (and definition of Misoperation), the term "Composite Protection System" is used while in other portions only the term Protection System is referenced. For example, within the definition of "Misoperation", items one through four use the term "Composite Protection System" while items five and six use the term "Protection System". **Response:** The term "Composite" was added to category 5 and 6 in the definition of "Misoperation." Change made. Another example is Requirement R1, Part 1.1 references the term "Protection System" while Part 1.2 references "Composite Protection System". ReliabilityFirst request the SDT's rationale on the appropriateness of the use of these terms. **Response:** The text involving Protection System component(s) (i.e., R1 or R2) is to provide a more granular look at the specific entity's protection whereas the text of Composite Protection System (i.e., Part 1.2 or 2.1) is referring to the broader condition where two or

Organization	Yes or No	Question 1 Comment
		more entities jointly own a Protection System that makes up a Composite Protection System. No change made.
Wisconsin Electric Power Company	No	We suggest revising #6 Unnecessary Trip -Other Than Fault: replace the 2nd sentence as follows: Current wording: "A Protection System operation that is caused by on-site maintenance, testing, ...is not a Misoperation" Suggested wording: "A Protection System operation that is related to on-site maintenance, testing, ... is not a Misoperation". This provides some flexibility to exclude operations not directly caused by on-site activity, but is a consequence of such activity. **Response:** The drafting team intends for this exclusion to apply only if the operation were directly initiated by on-site activities. A clarification was made to category 6.
Manitoba Hydro	No	(1) Manitoba Hydro believes that the definition of Misoperation needs to be re-written for the following reasons: a. It is not clear whether the six categories of Misoperations is exhaustive. The definition should be revised to clarify this. **Response:** The six categories are "exhaustive". The drafting teams contends that any Misoperation would fit within one of the categories. No change made. b. Under category 3, it is not clear if the cited example is the only type of Misoperations. **Response:** The portion "[d]*elayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability…"* has been removed. Change made. More explicit criteria has been provided to add the necessary clarity.

Organization	Yes or No	Question 1 Comment
		c. Use of the phrase “slower than required” in category 3 and 4 of the definition is unclear and does not capture the intended meaning identified in the Application Guidelines. The Guidelines state that “required” actually means as intended by the owner. Thus, this terminology should be used. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. d. Based on the numerous examples in the Guidelines of what is and is not a “Misoperation”, as well as references in the Guidelines to the effect that SMEs recognize that judgment must be used, the definition itself should clearly incorporate the notion of judgment by the owner. While the first sentence of the definition refers to intention, it does not specify whose intention (manufacturer, designer, operator..?) **Response:** The drafting team has modified the definition of “Misoperation” to address this concern. Change made. The proposed definition of “Slow Trip” simplifies the criteria; therefore, simplifying the determination. The Application Guidelines has been updated to clarify the intent of the drafting team in using the word “intended” in the definition of “Misoperation.” e. The sentences about component failure are out of place given that the definition of Composite Protection System is the total system, not individual components, and given that the first sentence of the definition refers specifically to failure of the Composite Protection System. **Response:** The intent is to provide clarity that a single component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made.

Organization	Yes or No	Question 1 Comment
		f. The word “intended” has been replaced with “required” even though the Application Guideline states that the term “required” is intended to refer to the objective of the owner. If this is the intended meaning, then the standard should use the wording “as intended by the owner”. The words “as required” are too vague and may be interpreted to mean as required to ensure the reliability of the BES. (Could it also mean as required by the designer / manufacturer or some other entity?) **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (2) Revise the definition of Composite Protection System to “The total complements of the Protection System(s) that function collectively to protect an Element, such as A and B system, any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.” **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter’s proposal above is provided using **blue with underline** for additions and ~~red with strikethrough~~ for deletions to illustrate the requested revision: “The total complements of the Protection System(s) that function collectively to protect an Element, such as **A and B system,** any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded.”
Flathead Electric Cooperative, Inc.	No	I do not like adding composite to the definition of protection system. This seems to broaden what is understood as a protection system and may impact testing and maintenance programs unnecessarily. I suggest sticking with the way it was before this redline change. **Response:** The drafting team is not modifying the current defined term Protection System, but defining a newly proposed term. No change made.

Organization	Yes or No	Question 1 Comment
American Electric Power	No	AEP recommends replacing "high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability" with "the lack of high-speed performance resulted in voltage or dynamic instability". The draft does not specify who is responsible to perform the identification, and adding "Planning Authority" would create a de facto TPL requirement. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Independent Electricity System Operator	No	We do not see the need to create a defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. In the comment report, it is indicated that 4 commenters representing about 24 individuals requesting clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing a new term which is redundant. We suggest to remove this defined term. **Response:** The reason for proposing the newly defined term, "Composite Protection System," is found in the Application Guidelines under the heading "Definitions." No change made.
Public Service Enterprise Group	No	We agree with the definition of Composite Protection System, but we believe that the categories definition of Misoperation could be improved. The standard does not address situations where one cannot determine whether the Protection System operated correctly or whether a Misoperation occurred. • Without evidence of a Fault associated with a trip, it is possible that Normal Clearing occurred, although there may be no evidence to support or reject that conclusion.

Organization	Yes or No	Question 1 Comment
		• Without evidence of a Fault associated with a trip, it is also possible that a category 5 (Unnecessary Trip - During Fault) or category 6 (Unnecessary Trip - Other Than Fault) Misoperation occurred; however, there may be no evidence to support or reject either reporting category. In order to address a situation when the operation of a Protection System cannot be determined to be a correct operation or a Misoperation, we believe a seventh Misoperation category should be considered: "Unclassified Trip: Any trip that (a) cannot be confirmed as the correct operation of the Protection System and (b) for which the evidence is not sufficient to place the trip into another Misoperation category." **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. See the Application Guidelines under the heading "Requirement R1." This will cause all such trips to be consistently investigated as Misoperations. We understand that many of these Misoperations may result in an undetermined cause.
Tacoma Power	No	In the definition of Misoperation, Unnecessary Trip - Other Than Fault, change "...caused by..." to "...related to..."In the definition of Misoperation, there may be some ambiguity/overlap in determining if some Misoperations are due to a Slow Trip or an Unnecessary Trip when Protection Systems are found not to have been adequately

Organization	Yes or No	Question 1 Comment
		coordinated. It is suggested that something like the following change be made to Slow Trip - During Fault and Slow Trip - Other Than Fault: Change "...or resulted in the operation of any other Composite Protection System..." to something like "...or a Protection System component failure resulted in the operation of any other Composite Protection System..." Inadequately coordinated relay settings would then more clearly fall under either Unnecessary Trip - During Fault or Unnecessary Trip - Other Than Fault. The only other remedy would be to categorize the Misoperation based upon the corrective action taken. (It should be noted that this ambiguity/overlap is only an issue if Misoperations must later be coded during a NERC data request.) **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. In the definition of Misoperation, Slow Trip - Other Than Fault, consider removing the reference to "...voltage or dynamic instability..." It seems that these issues may be more related to Fault conditions. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Southern California Edison Company	No	There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry. **Response:** The "Misoperation" definition has been modified to address this issue. Change made.
Xcel Energy	No	1) The definition for Composite Protection System could be clearer. For example, are the relays deployed at all ends of a transmission line for the protection of that line considered a part of one Composite Protection System? Does the presence or

Organization	Yes or No	Question 1 Comment
		absence of a communications-assisted scheme change which relays would comprise the Composite Protection System? **Response:** Yes, relays deployed at all ends of a transmission line, which is an Element, that function collectively to protect that line are considered a part of the line's Composite Protection System. The presence or absence of a communications-assisted scheme does not change the application of the proposed definition. The Application Guidelines section has been updated to address this issue. Change made. 2) The definition of Composite Protection System should be modified to account for all of the elements that may or may not operate to protect an element, excluding breaker failure protection. Breaker Failure protection should be considered its own zone of protection. Suggested change as follows: The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. Breaker failure protection should be considered as protecting its own specific breaker element. **Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made**. A redline of the commenter's proposal above is provided using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. **Breaker failure protection should be considered as protecting its own specific breaker element**." 3) We have two issues driving our negative vote. The first issue is that high speed performance requirements for identified Composite Protection Systems are not defined or

Organization	Yes or No	Question 1 Comment
		controlled by a single entity with regional grid performance knowledge, such as Transmission Planning. Without centralized accountability to identify performance requirements for specified systems, settings will be installed according to the PRC-001 coordinated settings implemented by the BA, and TO or GO system owners. These settings have been coordinated with the applicable entities. Transmission Planning is the entity that should be cognizant of settings required to maintain system stability under various fault conditions, and notify TO system owners of these requirements for inclusion in PRC-001 coordination. This coordination needs to be identified, tracked, and proper timelines for implementation identified. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. 4) The second issue driving our negative vote is the lack of a time requirement tied to when a “previously identified” high-speed performance need has to be implemented. For example, under the Slow Trip - During Fault, the phrase “ ...if high-speed performance was previously identified...” has no time horizon to make this an effective requirement. If a high speed, 3 cycle fault clearing requirement was identified by e-mail the previous day, and the device was not reset immediately, and a subsequent event caused the device to operate at 30 cycles, a Misoperation would result. Instead, a process by which requirements are identified by the planner, allowing an defined period for implementation, should be required. This could be accomplished by either adding Transmission Planning as an applicable entity with notification requirements defined in the requirement language, or including the GO/TO/Distribution provider as a partner in this process in another standard, such as PRC-001 or the TPL series. Proposed rewording is as follows: Misoperation: The failure of a Composite P0rotection System to operate as intended and previously coordinated. Any of the following is a Misoperation:

Organization	Yes or No	Question 1 Comment
		Slow Trip - During Fault - A Composite Protection System operation that is slower than for a Fault condition for which it is designed and coordinated. Delayed clearing of a Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. Slow Trip - Other Than Fault - A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed and coordinated, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. And similar edits to all other fault definitions in the document, removing the "...previously identified..." language. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Texas Reliability Entity	No	Texas RE is concerned that the revised definition of Misoperation is limited to failure of a Composite Protection System, and that this standard does not require investigation and mitigation of all Protection System operations/failures to operate when they are sub-parts of a Composite Protection System. We submit that any failure to operate as designed should be investigated and mitigated, even if another part of the Composite Protection System covered for the malfunctioning component/system. **Response:** The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Organization	Yes or No	Question 1 Comment
		The purpose of having the definition of Composite Protection System is to promote reliability and not to penalize entities for implementing redundant protection (e.g., primary and secondary protection). A failure of the primary system when secondary system operates correctly is not a Misoperation because the Composite Protection System operated correctly to protect the given Element. The Application Guidelines section has been updated to address this issue. Change made.
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy agrees with the new definition for Composite Protection System and believes it is needed to support consistent misoperations reporting. However, we suggest additional clarifications for the two Slow Trip categories of Misoperation definitions that were revised to address high-speed performance. The second sentence of the two Slow Trip categories of Misoperation definitions states: 'Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System'. We recommended changing this sentence to state the following: 'If the Composite Protection System is comprised of two, or more, independent high-speed schemes, delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or if high-speed performance was previously identified as being necessary for coordination with other Composite Protection Systems.' **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Indiana Municipal Power Agency	No	We see no alternative other than to install SOE equipment and/or Disturbance Monitoring Equipment and/or Digital Fault Recorders to monitor the Composite Protection System

Organization	Yes or No	Question 1 Comment
		during operations/Misoperations of BES interrupting devices. With the current definition of Misoperation, especially the Slow Trip definitions, it will be crucial to the investigation to have exact Protection System parameters and operation times prior to, during, and immediately following any operation on a BES interrupting device. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. In short any Protection System element (any device subject to PRC-005) must now be logged, recorded, and archived in order for a Registered Entity to be able to go back and show that their Protection System/Composite Protection System operated as designed and did not contribute to a Misoperation on either their own BES interrupting device and/or an adjacent Registered Entity’s BES interrupting device. This will be a considerable expense for smaller GOP’s and DP’s to install, operate, and maintain the equipment and archive the data and records required to meet the burden of these proposed definitions. **Response:** The proposed standard is not prescriptive and provides the applicable entities flexibility in choosing how they log, record, and archive data and records. No change made.
Tri-State Generation and Transmission Association, Inc.	No	We believe that the term “local backup” includes breaker failure relaying, but it appeared at the webinar that the drafting team does not intend for breaker failure relaying to be included in the definition of Composite Protection System. We recommend that “local backup” be removed from the definition or changed to “local backup (excluding breaker failure protection).” **Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made.**
Liberty Electric Power LLC	No	The maintenance exclusion should include failure to trip as well as trip. Take for example a deliberate roll of a lock out relay as a unit comes offline to test the system. Under the

Organization	Yes or No	Question 1 Comment
		definition if the test caused an early trip it would not be an misoperation. But it is unclear if a failure to trip during the test would be a misoperation. **Response:** The drafting team has modified the definition of "Misoperation" to address this example. Change made.
Florida Power & Light	Yes	No comments on the modified "Composite Protection System" definition. However, confusion may result in trying to determine whether an item fits into Misoperation Category 1 "Failure to Trip-During Fault" or into the Category 3 "Slow Trip-During Fault" definition. In both cases, the fault is likely be isolated by remote backup protection schemes. Consider combining Categories 1 and 3. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. The Composite Protection System will not have operated for a Failure to Trip; whereas, for a Slow to Trip Composite Protection System operation, an operation would have occurred. Either way both are a Misoperation. Also, regarding Category 6 "Unnecessary Trip-Other that Fault," the included wording is somewhat confusing. Consider revising to: "Spurious operation of a protection system in the absence of a fault condition on the power system it is designed to protect." **Response:** The drafting team declined to use "Spurious…" as suggested, but made other modifications to the Unnecessary Trip – Other Than Fault portion of the definition of "Misoperation." Change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company;	Yes	Yes, provided that it is made plain that, for the purposes of reportability, the failure or misoperation of an individual component of the Composite Protection System is not to be considered a reportable Misoperation when the Composite Protection System taken collectively functionally did not misoperate. Without this clarification, it is still confusing to

Organization	Yes or No	Question 1 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		state that the failure (misoperation) of an individual component of a Composite Protection System is not a misoperation. We suggest adding "reportable" to all occurances of the phrase "is not a misoperation" to read "is not a reportable Misoperation" where the phrase occurs in the draft standard (12 occurances). **Response:** The intent is to provide clarity that a single component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made. Reporting has been removed from the standard; therefore, adding this language would not add clarity. No change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[2] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. The definition of Misoperation, items 5 and 6 need to have the word Composite inserted between unnecessary and Protection. **Response:** The drafting team has modified the definition of “Misoperation” to address this concern. Change made.
ACES Standards Collaborators	Yes	The definition of Misoperation is much improved. We thank the drafting team for proposing a definition for Composite Protection System. It adds clarity to the standard. **Response:** Thanks you for your support.

[2] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	ATC agrees with the new and revised definitions, but recommends additional clarification around Slow Trip. Would a study be needed to indicate where high-speed performance was previously identified for a Slow Trip? The Slow Trip definitions infer that in order to correctly or incorrectly declare a Misoperation, a study would need to occur. Such study would need to pre-date the operation. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made.
Entergy Services, Inc.	Yes	There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate? **Response:** In the example above, this is not a Misoperation of the Composite Protection System. The Application Guidelines have been revised to add clarity concerning this issue. Change made. The definition of Composite Protection System is still vague to this. Suggest the below definition: The total complement of the Protection System(s), with respect to the protective relay of interest, that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. **Response:** The definition of Composite Protection System and the associated Application Guidelines section has been modified to improve clarity. Change made.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	Yes	Please clarify the following; the composite protection system also includes the potential transformers, current transformers, battery bank and charger? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Exelon	Yes	We support the definition for Composite Protection System. **Response:** Thank you for your support.
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Tennessee Valley Authority	Yes	
ReliabilityFirst Protection Subcommittee	Yes	
SERC Protection and Controls Subcommittee	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 1 Comment
Muscatine Power and Water	Yes	
LCRA Transmission Services Corp	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Québec Production	Yes	
Cowlitz PUD	Yes	
ITC	Yes	

2. **Based on stakeholder input, the drafting team modified the previous Requirement R1 to clarify responsibilities where two or more entities share ownership of a Protection System. The proposed Requirement R2 determines when other entities are notified and Requirement R3 now clarifies that the notified entity has the greater of 60 calendar days from notification or 120 calendar days from the BES interrupting device operation. Do you agree this modification clarified the performance for notification (R2) and the notified (R3)? If not, please provide specific suggestions for improvement.**

Summary Consideration: Of the 53 commenters that responded to this question regarding the first three Requirements in the standard, more than two-thirds support the standard drafting team's (SDT) revisions and approach. The majority of commenters responding "no" to the question had concerns that the SDT addressed with a revision to the standard. The following is a summary of the significant comments and whether the concern resulted in a change or not.

There were approximately two majority comments, both of which resulted in a revision to the standard. Two comments supported by 26 individuals noted that the one or more of the Measures were insufficient. The SDT provided additional detail in the Measures. Second, approximately three comments supported by ten individuals raised concerns about notification of other owners. To address these concerns, the SDT revised Requirement R2, 2.1, to read: "notification of the operation shall be provided to the other owner(s) that share *Misoperation identification responsibility* for the Composite Protection System." This is intended to allow the initiating entity to identify and notify the appropriate owner that needs to review the BES interrupting device operation for Misoperation.

A minority issue identified by two individuals revealed a significant gap in the standard for the case of a BES interrupting device that failed to operate. If this condition occurred, there would have been no specific performance for an entity to initiate the Requirement(s). To address this, the SDT revised Requirement R2 by creating two discrete conditions for notification. For the case of the BES interrupting device failing to operate, a remote BES interrupting device would have operated. It would be this device owner in Requirement R2 that would have an obligation to notify the other owner for which backup protection was provided to close the gap.

There were two significant majority issues that did not result in a change. The first concerns joint owners and there were approximately eight comments supported by 23 individuals that requested either a Requirement to have agreements between joint owners or how to address cases where the equipment is owned by the same entity, but different functions. The SDT provided detailed responses below for each of these comments. In general, if a single entity can meet the standard's objectives and support its compliance under Requirement R1, there is no need to make notifications; however, Requirement R2 is provided to ensure that other owners or entities that share Misoperation identification responsibility for the Composite Protection System are notified.

Other minority comments were too numerous to list in this summary, but are detailed in individual responses, below. Some include confusion about notifications and the time periods. Others revealed confusion between identifying the Misoperation and identifying the cause of the Misoperation. One comment requested special handling for extenuating circumstances and another requested the Distribution Provider to be excluded from the standard's Applicability.

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	No	To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, the NSRF proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden.

Organization	Yes or No	Question 2 Comment
		Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: 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. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.
FirstEnergy Corp	No	R1 and R2 refer to identification and notification "... within 120 calendar days of the BES interrupting device operation ...". Currently, submittals to the Regional Entity are due 60 days following the end of a quarter, which could conceivably place it up to 150 days following an event. Besides having to move up the review of Protection System operations, what Evidence will be required to prove the 120 day identification and notification? **Response:** The RSAW will provide the audit approach to determining compliance. Acceptable evidence is listed in each Requirement's Measure. No change made.

Organization	Yes or No	Question 2 Comment
PPL NERC Registered Affiliates	No	The expression, "identify whether its Protection System component(s) caused a Misoperation when," in R1 should be changed to, "identify whether (a) its Protection System component(s) caused a Misoperation, (b) functioned correctly or (c) a Misoperation cannot be ruled-out, when." NERC acknowledges in R4 that many months or even more than a year may be needed to authoritatively classify a relay operation, and this possibility is noted also in R2.2, but R1 requires passing Misoperation-vs.-no Misoperation determination within 120 days. It was stated in the 2/20/2014 Protection Systems Misoperation Webinar that such situations should be addressed by initially assuming a Misoperation, and later ask that the coding be changed if this proves not to be the case. The PPL NERC Registered Affiliates submit (per the guidelines issued by RFC) that in the absence of evidence, a Misoperation should not be assumed. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made.
Dominion	No	The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	FMPA believes there are still ambiguities regarding the responsibility where to or more entities share ownership of a Protection System. Specifically as R1 relates to R2 the language reads in a way that seems to imply entities are required to wait to provide notification of the ongoing investigation to one another, which we believe is not the intent. **Response:** It is not the intent to require entities to wait to provide notification. A period of 120 calendar days after a BES interrupting device operation is provided for the BES interrupting device owner to perform Requirement R2. If the BES interrupting device owner determines from parts 2.2 and 2.3 that a notification is warranted they have the remainder of the 120 calendar day period to make notification. They do not have to wait for the 120 calendar day period to expire before making notification. No change made. Requirement R2 has been redrafted for clarity but the intent remains the same. Furthermore please clarify; where BES interrupting devices are associated with multiple Composite Protection Systems; Does 1.2 refer to the Composite Protection System which is believed to have operated or to all Composite Protection Systems associated with the BES Interrupting device (which may or may not be owned by the same entity)? **Response:** Requirement R1, Part 1.2 is referring to the Composite Protection System that initiated the BES interrupting device operation. No change made.
Virginia State Corporation Commisison	No	R1 remains very unclear to me. The text requires a TO, GO or distribution provider to "identify whether" its component caused a misoperation, but Subparagraph 1.3 requires, as a necessary condition to such identification that the "BES interrupting device owner [has] identified" that its component caused the failure. This is circular. **Response:** Parts 1.1 through 1.3 are the criteria for which BES interrupting device operations have to be reviewed under R1 within 120 calendar days. Part 1.3 says “caused the BES interrupting device(s) operation” not caused the failure. If all three are true, then the entity must review (i.e., determine) whether its Protection System component(s) caused a

Organization	Yes or No	Question 2 Comment
		Misoperation. Similarly, Requirement R2 uses the same concept, but for determining the notification of others. No change made.
ReliabilityFirst	No	The term “BES interrupting device” is used throughout Requirements R1, R2 and R3 though it is only defined within the Application Guidelines section. In order to provide clarity and avoid potential interpretations of what constitutes a “BES interrupting device”; ReliabilityFirst recommends the SDT propose this as a new definition which would be added to the NERC Glossary of Terms. ReliabilityFirst recommends the following definition from the Application Guidelines for consideration: “BES Interrupting Device - A BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current.” **Response:** The drafting team asserts that the phrase “BES interrupting device” is widely understood by industry through both the absence of comments and the description in the Application Guidelines. No change made.
Wisconsin Electric Power Company	No	There appears to be a gap between R1 and R2 for the case when an interrupting device operates, but the interrupting device owner does not own any part of the Protection System(s) that tripped or may have tripped the device. The assumption in the draft is that the interrupting device owner also owns a portion of the Protection System, but this may not always be true. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made. Requirement R2 has been modified to address these concerns. Change made.

Organization	Yes or No	Question 2 Comment
David Kiguel	No	The standard should require that the Connection Agreement(s) among owners must address the procedures and potential dispute resolution for the case of 2 or more owners involved in the Misoperation investigation and CAP. **Response:** The drafting asserts this suggestion is administrative in nature and does not support reliability overall. The proposed standard mandates the necessary obligation for each entity of the jointly owned Protection System. Development and implementation of a Corrective Action Plan (CAP) to correct the Protection System component(s) of an identified Misoperation is incumbent upon the entity that owns the component. No change made.
Muscatine Power and Water	No	To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, MP&W proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden.

Organization	Yes or No	Question 2 Comment
		Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: 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. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.
American Electric Power	No	1) AEP recommends revising R1 section 1.2 as follows to recognize that a BES interrupting device may be part of multiple Composite Protection Systems: "The BES interrupting device owner owns all or part of the Composite Protection System(s); and". **Response:** Requirement R1, Part 1.2 is referring to the Composite Protection System that initiated the BES interrupting device operation. No change made. 2) AEP recommends revising R2 section 2.1 as follows: "The BES interrupting device owner shares the Composite Protection System(s) ownership with any other entity; and".

Organization	Yes or No	Question 2 Comment
		Response: Requirement R2, Part 2.1 is referring to the Composite Protection System that initiated the BES interrupting device operation. Requirement R2 has been modified. The previously drafted R2 Part 2.1 is now R2 Part 2.1.2. Change made. 3) AEP recommends adding the following footnote to the "entity" reference in R2 section 2.1: "In this context, "entity" denotes functional entity. A Composite Protection System owned by different functional entities within the same registered entity satisfies the R2 section 2.1 criteria." **Response:** A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the R2 section 2.1 criteria. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be completely covered in Requirement R1. Part 2.1 of Requirement R2 has been modified to address this concern. Change made. 4) AEP recommends adding the following footnote to the "entity's" reference in the first bullet of R5: "In this context, "entity" denotes functional entity". **Response:** The drafting team does not agree the suggestion provides additional clarity. Entity customarily denotes functional entity. No change made. 5) AEP recommends adding the following footnote to the "120 calendar days" reference in R2 and R3: "This timeframe may be extended, for operations occurring within a specified time period, by the Regional Entity if it determines that extenuating circumstances such as a natural disaster make it impractical to complete R1 or R2 within the allotted timeframe". **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating

Organization	Yes or No	Question 2 Comment
		circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Exelon	No	Please address who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. Otherwise we have no concerns with R1. **Response:** While a BES interrupting device may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. For R2 and R3, the date timeframes for a shared responsibility Protection System to a common interrupting device short cycles the non-owner of the interrupting device. A suggestion for shared responsibly; With R2 - the BES device owner should notify the Other Protection System owners within 30 calendar days of the operation and the device owner has 120 days calendar days to identify if it's Protection System caused a misoperation. For R3, the notified Protection owner should then have 120 from notification to identify if its Protection System misoperated. This time frame for R3 would provide the non-owner sufficient time for any scheduled outages to make a determination.

Organization	Yes or No	Question 2 Comment
		Response: Notification in Requirement R3 starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners pursuant to Requirement R2 when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners (i.e., upon notification), especially when there is little possibility that another owner's Protection System component(s) caused a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification within 120 calendar days. This is the concept the drafting team is employing in Requirement R3 which considers the informal communication and the exchange of information. Should an entity receive notification, it always has a minimum of 60 calendar days and probably has a good idea of the problem; otherwise, if a notification (i.e., official notification) happens early on, the entity is now subject to compliance under Requirement R3. If the entity has not ruled out a Misoperation, it should assume it is a Misoperation, at which time, Requirement R4 will enable the entity to continue its investigation into the cause or no cause found. No change made.
Xcel Energy	No	1) There appears to be a potential gap if a Composite Protection System wholly owned by one entity experiences a Failure to Trip, and only interrupting devices wholly owned by another entity operate. 2) Propose wording change for R1 through R3 as follows: "R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Associated Composite Protection System component(s) Misoperated when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; "R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES

Organization	Yes or No	Question 2 Comment
		interrupting device operation, notify the other owner(s) of the Associated Composite Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; and "R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Associated Composite Protection System component(s) caused a Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]" **Response:** Requirement R2 has been modified to address these concerns. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~red with strikethrough~~ for deletions to illustrate the requested revision: "R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its **Associated** **Composite** Protection System component(s) ~~caused a Misoperation~~ **Misoperated** when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; "R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the **Associated** **Composite** Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; and "R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its **Associated** **Composite** Protection System component(s) caused a

Organization	Yes or No	Question 2 Comment
		Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"
Texas Reliability Entity	No	There are several cases in the ERCOT Region where Company A owns the interrupting device and Company B owns the Protection System. In these cases, subpart 1.2 for R1 and subpart 2.1 for R2 do not apply. The language for Requirements R1 and R2 is written such that all of the subparts (1.1, 1.2, and 1.3 for R1 and 2.1, 2.2, and 2.3 for R2) must apply for the entity to initiate the analysis of the operation or notification. We would suggest modifying the language for R1 and R2 to say that the Requirement applies if one or more of the subparts apply. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made.
Hydro-Québec Production	No	For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system. For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team agrees this is a best practice; however, it is not useful having a Requirement for each entity to share information. The way the Requirements are written, it is in the best interest of all parties (i.e., jointly owned Protection Systems) to share or communicate information about operations which meet the criteria for Requirement R1 and R2. Having such a Requirement is administrative and provides little, if any, reliability benefit. No change made.

Organization	Yes or No	Question 2 Comment
Tri-State Generation and Transmission Association, Inc.	No	We generally agree but we have some concerns about multiple entity ownership of different Protection System components compared to joint ownership of individual components. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
Northeast Power Coordinating Council	Yes	We agree with the requirements as revised, but do not agree with Measures M2 and M3. a. Measure M2: The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. **Response:** The Measures have been updated. Change made. b. Measure M3: The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. **Response:** The Measures have been updated. Change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power	Yes	If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.

Organization	Yes or No	Question 2 Comment
Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden. **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations but were not accounted for within Requirement R1. No change made.
ACES Standards Collaborators	Yes	(1) While we agree the revisions to these requirements clarify what is required, we feel that R2 meets P81 criteria. First, R2 meets P81 criterion A because the requirement of notifying another owner does little to support reliability. Second, R2 meets P81 criterion B1 because it is clearly administrative, and it meets P81 criterion B4 because it requires reporting to another party. Without significant justification for how this administrative, reporting requirement materially and substantially supports reliability, we cannot support it. We suggest that requirement R2 should be removed and an explanation of the desired reporting would be appropriate in the Application Guidelines. The Application Guidelines on page 28 in the first paragraph acknowledges that "notifying the other owners... may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability." **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. No change made. (2) If Requirement R2 persists, we cannot support a medium VRF for R2. This requirement simply does not rise to the level of having an "impact on the electric state or capability of the bulk electric system" which is what is required to meet the Medium VRF criteria. The requirement is an administrative requirement and does not have any impact on the electric state or capability.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team disagrees because a lower Violation Risk Factor (VRF) is 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. However, any unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. Because of this, the drafting team has selected a VRF of Medium. Please refer to the VRF/VSL Justification document. No change made. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the applicability section. By definition, the Distribution Provider cannot own a “BES interrupting device” since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. If they are not, then NERC/regional entity has made a determination per Note 1 in the statement of compliance registry criteria that the BES interrupting device does not have a material impact on the reliability of the bulk electric system and has not registered them. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the requirement to apply to the Distribution Provider.

Organization	Yes or No	Question 2 Comment
		Response: The Distribution Provider (DP) provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. In this case, the DP may own a non-BES Protection System which operates a BES interrupting device. This rationale supports including the DP as an applicable entity in the proposed standard. Also, BES interrupting device "mechanisms" are not a part of the Protection System as noted in the Application Guidelines; however, the trip coil(s) is a part of the BES interrupting device and Protection System. No change made. (4) Requirement R3 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the responsible entity "to identify whether its Protection System component(s) caused a Misoperation." If a responsible entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes the Violation Severity Level of Severe here is for failing to perform the Requirement, not failing to properly identify the operation as a Misoperation. No change made.
ReliabilityFirst Protection Subcommittee	Yes	There was some confusion on who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
SERC Protection and Controls Subcommittee	Yes	1. Recommend that R1.3 be simplified by rewording to indicate that "The BES interrupting device owner identified that its Protection System component(s) caused the Misoperation." **Response:** Although the drafting team understands the reason for the suggestion, it does not meet the intent of the three Parts 1.1 through 1.3. The three Parts are criteria which must be met to determine whether the Protection System operation is a reviewable event by the entity. The Misoperation is determined under the main Requirement R1, if the event meets the three Parts. No change made. A redline of the commenter's proposal above is provided using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "The

Organization	Yes or No	Question 2 Comment
		BES interrupting device owner identified that its Protection System component(s) caused the Misoperation ~~the BES interrupting device operation~~." 2. The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the Misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. 3. Please add an explanation in the R2 Application Guidelines for situations in which one group investigates for multiple registered entities. It's quite common for a single protective relay engineering group to investigate for the TO, GO, and DP that their company owns. We suggest the following note "(Note: In cases where a single group performs an overall investigation for several entities each with some ownership of the Composite Protection System; a single document (or electronic database) is sufficient to meet the R2 and R3 notification requirements for use by both Registered Entities.)" be added to the Rational boxes for R1, R2 and R3 as well as to the Application Guidelines. This reduces the administrative overhead of having to send yourself an email just to prove that R2 and R3 are met. The important action of identifying and correcting Misoperation causes is still done and duly documented. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made.

Organization	Yes or No	Question 2 Comment
		A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made. 4. Please augment M2 with 'databases' to more clearly allow for a single group investigating on behalf of multiple entities (e.g., GO, TO, DP) to date the notification within their database. For example, CTs on a GO breaker may be part of an adjacent TO switchyard bus protection, so there are two entity owners regarding the Composite Protection System. If owned by the same corporation, one system protection group investigates on behalf of the GO and TO, and act to identify and correct Misoperation causes. **Response:** The drafting team notes that the Measures for the Requirements above include examples of evidence and are not all inclusive. Other forms of evidence may be used at the entity's discretion. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	ICLP believes that the latest draft of PRC-004-3 corrects a gap where a delayed investigation by one entity could lead to a finding of a violation on the other. Requirements R2 and R3 address this potentially unfair scenario. **Response:** Thank you for your comment and support.
Ameren	Yes	(1) Ameren adopts all the SERC PCS comments by reference. **Response:** Please see the response to the SERC Protection and Controls Subcommittee. (2) A primary reason for our negative ballot on this draft 4 is the proposed clarification (included with SERC PCS comments) to allow a System Protection group of one company's TO, GO, and DP to document R2 and R3 notifications within its database or PRC-004 software, rather than exchange emails or Faxes.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes that the Measures for the Requirements above include examples of evidence and are not all inclusive. Other forms of evidence may be used at the entity's discretion. No change made.
ITC	Yes	ITC Holdings is concerned with the documentation requirements to track communications between the BES interrupting device owner and the protection system owner. An auditor may become more interested in communication dates being more important to them than identifying the cause of the misoperation and implementation of the corrective action plan. **Response:** The drafting team asserts that entities may have varying and multiple communications in their efforts to identify potential Misoperations. Evidence must demonstrate that the BES interrupting device owner communicated to other owner(s) (i.e., Requirement R2). For the notified entity, it would demonstrate receipt of notification from the BES interrupting device owner (i.e., Requirement R3). No change made.
US Bureau of Reclamation	Yes	
JEA	Yes	
Arizona Public Service Company	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	Yes	
Manitoba Hydro	Yes	
PJM Interconnection	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Transmission Company	Yes	
LCRA Transmission Services Corp	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery Company LLC	Yes	
Public Service Enterprise Group	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Northeast Utilities	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Cowlitz PUD	Yes	
Liberty Electric Power LLC	Yes	

3. **Based on stakeholder input, the drafting team removed the previous Requirement R3 (action plan) and proposed a new Requirement R4 which provides entities time to investigate the Misoperation to determine its cause(s). Do you agree this modification clarified performance and removed ambiguity regarding the action plan? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 52 commenters responded to this question about the replacement of the previous "action plan" with "investigative actions." More than half agreed with the proposed change. The majority of commenters responding "no" to the question had concerns that the standard drafting team (SDT) addressed with either a revision to the standard or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

There were two significant majority comments. First, two comments supported by approximately 33 individuals identified problems with the Measure(s). The SDT corrected the issue by adding the necessary text. Second, two comments supported by about 26 individuals were concerned about how "investigative actions" would be handled by an auditor or what constituted an investigative action to demonstrate compliance. The SDT provided additional information in the Application Guidelines. There was one minority comment by two individuals that requested clarification about the timeframes used in Requirement R4. The SDT made clarifications in the Application Guidelines to note that timeframes are distinct and separate from the other Requirements.

There were no majority comments in this section, but there were a number of minority comments and too many to summarize in a meaningful way in this summary; detailed responses are provided in response to individual comments, below. The following are the most notable. Approximately six individuals had varying concerns about the auditability of Requirement R4, whether or not it is measurable, that the timeframes are either too constrictive or open-ended, or if the times are separate from other Requirements. The SDT contends the timeframes are reasonable given that investigative actions may take several months to complete between actions. For example, scheduling an outage of a transmission line. The timeframes are distinct. Two commenters believe the Requirement R4 should require the entities to determine the cause rather than indirectly assuming the cause would be found in Requirements R1 or R3 which focus on Misoperation identification. Another commenter requested a provision for extenuating circumstances which is better handled through the enforcement space according to the NERC Rules of Procedure.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	We agree with the requirements as revised, but do not agree with the Measures. Measures: The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. **Response:** The Measures have been updated. Change made. The term "investigative action(s)" is ambiguous even given the example cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. **Response:** The Application Guidelines has been updated to provide additional guidance on the expectation of investigative actions under the section heading "Requirement R4." Change made.
MRO NERC Standards Review Forum	No	The NSRF believe that there are many potential forms of "owners" and that "owners" needs to be modified to read, "other NERC registered applicable entities" to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don't have any impact on the operation of the protection systems. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp	No	Does NERC intend to be prescriptive with respect to a template for a Corrective Action Plan, or will the Regional Entities accept whatever format and tracking documentation is provided by the Registered Entities, even though they may be varied among the Entities? **Response:** There is nothing prescriptive in the Requirements concerning a Corrective Action Plan. The entity may use its discretion to determine how to create it. By definition, a CAP contains actions and a timetable to remedy a specific problem. No change made. The measures identified in M6 seem as though they could be subject to interpretation by an Auditor. **Response:** The Measures have been updated. Change made.
PPL NERC Registered Affiliates	No	The expression, “or that decided a Misoperation cannot be ruled-out,” should be added in R4 after, “has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3,” per the rationale in our comment above for R1. The outcomes listed under R4 should be expanded as shown below; since, if there are Misoperations for which no cause can ever be identified, there can also be possible-Misoperations for which a yes-or-no determination can never be made. • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven. **Response:** The 120 calendar days is to determine whether or not a Misoperation occurred. The intent of the definition of “Misoperation” and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the

Organization	Yes or No	Question 3 Comment
		continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • **A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven**.
Tennessee Valley Authority	No	Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording to allow additional time when a utility endures a natural disaster. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) This requirement should be modified to simply state that the applicable entity is required to identify the cause of the Misoperation or document that a cause could not be found. It is too prescriptive that an applicable entity must identify investigative actions each successive two calendar quarters. This makes the requirement inflexible and needs to be simplified. Consider an example where an applicable entity that should be performing more investigative actions every two successive calendar quarters can be compliant by simply identifying one and an applicable entity in a unique situation that cannot perform even a single investigative action in the two successive calendar quarters due to extenuating circumstances would be in technical non-compliance. **Response:** The drafting team asserts that Requirement R4 mandates the applicable entity to exercise due diligence to pursue the cause of the Misoperation until the cause is found or document that a cause could not be found. Requirement R4 is structured in such a way to ensure identified Misoperations with no cause are either investigated to identify the cause or that a declaration is made to close the investigative action(s) if no cause is identified. In addition, a requirement needs to be auditable and measureable. No change made. (2) This requirement incorrectly implies that R1 and R3 require the applicable entity to identify the cause of the Misoperation. They do not. Rather, R1 and R3 simply require the applicable entity to identify Misoperations. Thus, R4 should be modified to simply require identification of the cause of the Misoperation subject to reasonable investigative actives or declaration that the cause could not be identified after completing reasonable investigative actions. **Response:** Requirement R4 is not applicable if the “cause” of the Misoperation is known. The “cause” may be found when performing Requirements R1 and R3. If not, Requirement R4 requires the entity to perform at least one investigative action every two calendar quarters following the identification of a Misoperation or make a declaration. No change made.

Organization	Yes or No	Question 3 Comment
ReliabilityFirst Protection Subcommittee	No	The direction included in R4 is awkwardly worded. Consider rewording the following “shall perform investigative action(s)... at least once every two full calendar quarters” AS “shall, on a semi-annual basis, continue to show evidence of investigation...”. However, the examples in the Application Guidelines are clear as to what the SDT is looking for. **Response:** The drafting team appreciates the suggestion and has decided to leave the Requirement as written. No change made.
ReliabilityFirst	No	ReliabilityFirst has a number of concerns with Requirement R4. First, from compliance/enforcement perspective, Requirement R4 is not sufficiently distinct from Requirements R1 and R3 (it creates a “double jeopardy situation”). For example, Requirement R3 requires the responsible entity to “...identify whether its Protection System component(s) caused a Misoperation”. As written, if the responsible entity fails to “...identify whether its Protection System component(s) caused a Misoperation” this could be grounds for a possible violation of Requirement R3. This is evident in the associated Violation Severity Levels where failing “...to identify whether or not a Misoperation its Protection System component(s) occurred” is a Severe Violation. This is in direct conflict with Requirement R4, which gives the responsible entity additional time to perform investigation actions to determine the cause of the Misoperation. ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish but from a compliance/enforcement standpoint it will cause issues. **Response:** Requirements R1 and R3 are for determining whether a Misoperation occurred or not. Requirement R4 is for determining the cause(s), if not determined while performing Requirements R1 or R3. Requirement R4 has been clarified. Change made. Second, as already noted, ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish, but notes that there is no ending time period associated with how long the responsible entity has to complete the investigation. As written, a responsible entity can hypothetically drag out the investigations and never officially complete the investigation.

Organization	Yes or No	Question 3 Comment
		ReliabilityFirst believes in order to close the loop, the responsible entity should be limited to four calendar quarters to complete the investigation (i.e., either identification of the cause(s) of the Misoperation or declaration that no cause can be identified). To address the two concerns, ReliabilityFirst recommends including similar language as noted in Requirement R4 as sub parts in Requirement R1 and R3 along with including an ending completion timeframe as well. The following is an example for consideration for Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. If the cause(s) of the Misoperation cannot be determined, the Transmission Owner, Generator Owner, and Distribution Provider shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters, but for no more than four calendar quarters after the Misoperation was first identified, until one of the following actions completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **Response:** The drafting team asserts that Requirement R4 is intended to allow the entity the time needed for identifying the cause(s) of a Misoperation. Shortening the period would have the unintended consequence of having entities prematurely declaring that the cause was not found. It is up to each entity to determine how long it wants to continue its investigative work to determine the cause(s) of a Misoperation. No change made.
Manitoba Hydro	No	(1) For R4, Manitoba Hydro does not think that there is a need to perform investigative actions to determine the cause of the Misoperation at least once every two full quarters.

Organization	Yes or No	Question 3 Comment
		Repeated investigative actions would not be productive in identifying the cause. We propose this requirement to read as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation, until one of the following is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified." **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation ~~at least once every two full calendar quarters after the Misoperation was first identified~~, until one of the following ~~completes the investigation~~ is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified."
Muscatine Power and Water	No	MP&W believes that there are many potential forms of "owners" and that "owners" needs to be modified to read, "other NERC registered applicable entities" to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1,

Organization	Yes or No	Question 3 Comment
		R2, R3, and R4 for joint protection system owners that actually don't have any impact on the operation of the protection systems. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
American Transmission Company	No	ATC's experience has been that the cause of a Misoperation is determined within the first couple months following its occurrence. If the cause is not found in that time, it is unlikely to be found. Relative to R4, the parameters around investigative actions are not very productive, as revisiting the same information after an extended period of time does not typically lead to determining a cause. **Response:** The drafting team agrees that most Misoperation cause(s) are determined in the first phase of review and afterward the likelihood of determine the cause diminishes; however, Requirement R4 allows the entity a mechanism to continue the investigation without being out of compliance with Requirements R1 or R3 as the case may be. The drafting team understands that entities may need to schedule additional investigation (i.e., activities) such as taking an outage or sending equipment off to manufactures for testing and inspection. Requirement R4 provides this avenue to promote determining the cause(s) of Misoperations. No change made. ATC recommends removing the language in R4 that speaks to investigative steps "at least once every two full calendar quarters after the Misoperation was first identified."

Organization	Yes or No	Question 3 Comment
		Response: The drafting team originally discussed not having a time period associated with Requirement R4; however, in considering that approach, it was determined that the Requirement would not be measurable or auditable. No change made.
Exelon	No	How soon after a misoperation can a declaration of no cause be submitted? **Response:** The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading "Requirement R4" provides additional direction regarding this comment. No change made. Exelon agrees that a prompt investigation of the event should occur and prudent corrective action be initiated as detailed in the new Requirement R4; however, if the Standard is allowing a provision for continued investigations then the other requirements in the Standard should align. Requirement R4 needs to be modified or R1 needs to be modified to align with each other. The current wording in R4 provides a requirement that cannot be met unless the entity is not in compliance with R1. R3 provides the wording such as "cannot rule out" and "or cannot determine". This wording needs to also be added to R1 for completeness. In addition, the wording in the VRFs and VSLs needs to be adjusted to accommodate those events where the cause of the interrupting device operation has not yet been determined. **Response:** Requirement R4 is not applicable if the "cause" of the Misoperation is known. The "cause" may be found when performing Requirements R1 and R3. If not, Requirement R4 requires the entity to perform at least one investigative action every two calendar quarters following the identification of a Misoperation or make a declaration. No change made.
Kansas City Power & Light	No	The inclusion of the following phrase is ambiguous. "..... shall perform investigative actions to determine the cause of the misoperation at least once every two full calendar quarters

Organization	Yes or No	Question 3 Comment
		after the misoperation was first identified, until one of the following completes the investigation: • The identification of the cause of the misoperation; or • A declaration that no cause was identified." I would remove "at least once every two full calendar quarters after the misoperation was first identified." If the drafting team wants to set a time limit on the investigation, then state a not-to-exceed time period. **Response:** The drafting team originally discussed not having a time period associated with Requirement R4; however, in considering that approach, it was determined that the Requirement would not be measurable or auditable. No change made. A declaration should be available once an entity has completed all of its diagnostic tests, even if the declaration comes in the first calendar quarter after the misoperation. During the NERC webinar, one of the drafting team members indicated that the declaration could be made at any time, but I can envision a Compliance Enforcement Authority reading the language of R4 and asking why you didn't fulfill the requirement to test in the second full calendar quarter. **Response:** The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading "Requirement R4" provides additional direction regarding this comment. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.

Organization	Yes or No	Question 3 Comment
		Response: Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
Public Service Enterprise Group	No	In R4, we find the phrase “two calendar quarters” unclear since it is referenced from the date when the Misoperation was identified. For simplicity, that phrase should be replaced with “180 days.” Also, there may be a need to extend the time. For example, if an investigation required removing a transmission line from service, one may not be able to obtain a clearance to do so within 180 days, so an investigation action could not be performed, resulting is a violation of R4. Therefore, the 180 day time frame should be allowed to be extended for good cause if the owner documents the cause of an extension. Our recommendation is to replace R4 with this language:

Organization	Yes or No	Question 3 Comment
		"Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every 180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause), until one of the following completes the investigation:" **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every ~~two full calendar quarters after the Misoperation was first identified~~ **180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause),** until one of the following completes the investigation:" Finally, in the "Rationale" text box, the phrase "(120 calendar days)" should be stricken since it does not apply to R3. If notice per R2 is given on day 120, the entity under R3 has 60 day time period, while if notice is given on day 1, it has a 119 day time period. **Response:** The drafting team believes the reference above is in error. The "(120 calendar day)" reference is in the rationale box for Requirement R4 to highlight that Requirements R1 and R3 are distinct and separate from the time period in Requirement R4. No change made.

Organization	Yes or No	Question 3 Comment
Northeast Utilities	No	The term "investigative action(s)" used in Requirement 4 is somewhat ambiguous even given the examples cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. Can simply confirming an outage schedule be enough of an investigative action to satisfy all compliance auditors as suggested in the Application Guidelines? **Response:** The Application Guidelines has been updated to provide additional guidance on the expectation of investigative actions under the section heading "Requirement R4." Change made.
Texas Reliability Entity	No	There should be an end time frame for this requirement. If an entity has not determined if a Misoperation occurred within 120 days of the interrupting device operation, they could conceivably continue to investigate the event for years, as long as they perform an investigative action at least once every 6 months. **Response:** The drafting team asserts that Requirement R4 mandates the applicable entity to exercise due diligence to pursue the cause of the Misoperation until the cause is found or document that a cause could not be found. Requirement R4 is structured in such a way to ensure identified Misoperations with no cause are either investigated to identify the cause or that a declaration is made to close the investigative action(s) if no cause is identified. In addition, a requirement needs to be auditable and measureable. The Application Guidelines under the heading "Requirement R4" provides direction regarding this question. No change made.
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy believes a requirement to perform investigative actions to determine the cause of a Misoperation at least once every two full calendar quarters after the Misoperation was first identified will result in repetitious investigative actions and scheduled outages and would provide little benefit.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading “Requirement R4” provides additional direction regarding this comment. No change made. Also, we do not believe a declaration is needed, since assigning a cause code of Unknown / Unexplainable is part of the misoperation analysis process. The Cause Code and an explanation of the exhaustive investigation and tests conducted should be sufficient. Therefore, we recommend Requirement R4 be deleted. **Response:** The declaration in Requirement R4 is meant to be distinct and separate from the reporting aspects under the NERC Rules of Procedure, Section 1600, Request for Information or Data for compliance purposes. No change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	On page 28 of the clean draft #4, in the first sentence of the R4 section, the words "the entity" appearing after the comma are redundant and are not needed. **Response:** The drafting team agrees and has removed the additional “the entity” from the sentence. Change made.

Organization	Yes or No	Question 3 Comment
Virginia State Corporation Commisison	Yes	I have one wording suggestion for R3. I suggest moving the words "shall identify" from their present location to follow immediately after "Requirement R2." The sentence would then read "Each TO, GO and Distribution Provider that receives notification pursuant to Requirement R2, shall identify within the later of 60 days.....device(s) operation, whether its Protection System component(s) caused a Misoperation." **Response:** The drafting team appreciates the suggestion and has decided to leave the Requirement as written. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	ICLP appreciates the precise language used in Requirement R4 - which allows sufficient time to investigate a Misoperation, while limiting it to within reasonable bounds. We agree that if a cause cannot be found through good faith investigation within two calendar quarters, there is little benefit to pursuing the case further. **Response:** The drafting team appreciates the comment and support.
American Electric Power	Yes	AEP recommends replacing “at least once every two full calendar quarters after the Misoperation was first identified” with “at least once every six month period after the Misoperation was first identified”. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Puget Sound Energy	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 3 Comment
JEA	Yes	
Arizona Public Service Company	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Dominion	Yes	
SPP Standards Review Group	Yes	
SERC Protection and Controls Subcommittee	Yes	
Wisconsin Electric Power Company	Yes	
PJM Interconnection	Yes	
LCRA Transmission Services Corp	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	
Hydro-Québec Production	Yes	

Organization	Yes or No	Question 3 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Cowlitz PUD	Yes	
ITC	Yes	
Liberty Electric Power LLC	Yes	

4. **The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 50 commenters responded to this question about the overall comprehensiveness of the Application Guidelines. Commenters were equally divided as to whether the Application Guidelines were sufficient. The majority of commenters responding "no" to the question had concerns that the SDT addressed with either a revision to the standard or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

The following is a summary of the comments that resulted in a change. There were four majority comment themes. First, approximately six comments represented by 24 individuals requested additional specificity concerning the definition of "Misoperation" with regard to categories 3 and 4 ("Slow Trip"). The SDT made several changes to the Application Guidelines in addition to revisions to the definition. Second, about seven comments supported by 13 individuals requested clarifications concerning equipment. The SDT made clarifications to the Application Guidelines in reference to sync check relays, breaker failure, reverse power relays, control functions, and mechanical parts of breakers. Third, approximately four comments supported by ten individuals requested clarity regarding who had responsibility for the Corrective Action Plan (CAP), the extent of the evaluation of other Protection Systems, and/or the reporting of Misoperations. The SDT provided clarifications in the Application Guidelines except for reporting which will be handled through the NERC Rules of Procedure, Section 1600, Request for Data or Information. The last majority comments requested various clarifications or examples for the definition of "Composite Protection System." The SDT provided additional narratives and examples for various BES Elements (e.g., transformer, generator, and transmission line). Other additions included improving discussion concerning investigative actions and the definition of "Misoperation" to include on-site personnel.

There were three notable minority comments which resulted in a change. One comment supported by 11 individuals was stating uncertainty whether to identify an operation as a "Misoperation" if unsure or to consider the operation "correct." The SDT provided additional clarification in the Application Guidelines on the approaches an entity could take to continue its investigation. Two comments from individuals requested clarification on how to handle multiple automatic recloses of a BES interrupting device by a Protection System. The SDT provided clarification based on existing NERC System Protection and Control Subcommittee guidance. Last, one commenter requested an exclusion of Remedial Action Schemes (RAS) and Special Protection Systems (SPS). The SDT provided an exclusion in the Applicability section of the standard to make clear this perceived sub-set of a Protection System is not applicable to the standard.

There were two majority comments which did not result in a change to the standard. First, there were approximately five comments supported by 22 individuals that were either concerned the Regional Entities would no longer review CAPs or wanted to know more about the reporting of Misoperations. The SDT provided feedback below in the responses and directed commenters to the data request concerning the reporting of Misoperations. Second, about five comments supported by 11 individuals raised questions as to whether a certain scenarios were a Misoperation. Some scenarios could be determined whether they were Misoperations or not by the information provided by the commenter, others could not. Most notable minority comments which did not result in a change include: a request to add undervoltage load shedding (UVLS), a provision for extenuating circumstances, and a requirement to share information between different owners of Protection Systems. The SDT noted that UVLS would be handled after industry approval, extenuating circumstances are best handled in the enforcement space according to the NERC Rules of Procedure, and the request to share information requirement would not have a reliability benefit.

Organization	Yes or No	Question 4 Comment
Puget Sound Energy	No	a) Application Guidelines could have more specificity, in addition to examples. For example, in #4 (Slow Trip - Other than Fault), it should be spelled out that each possible Misoperation should be studied to test for possible effects on system stability. Other specific expectations, if any, should also be spelled out. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. b) In addition, “Other than Fault” should be clarified and explained together with the definition of SPS/RAS, which are excluded from PRC-004. (SPS/RAS are defined as non fault protection schemes). **Response:** The drafting team contends that “Other than Fault” does not need further clarification.

Organization	Yes or No	Question 4 Comment
		Response: Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. c) UFLS/UVLS should always be mentioned together in PRC-004-3 (unless both are not included). **Response:** Currently, underfrequency load shedding (UFLS) is applicable to the proposed standard to close a gap in reliability. No change made. Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. d) Should sync check and breaker failure be considered in the Application Guidelines - what category do these fall into? **Response:** Sync check is not included as a part of a Protection System and is not within scope of the proposed standard. Breaker failure has been clarified in the Application Guidelines. Change made. e) In all six parts of the Misoperation Definition, the phrase "...where tripping for protection purposes is involved" could be included for clarity. **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made.
US Bureau of Reclamation	No	Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a

Organization	Yes or No	Question 4 Comment
		transmission line so that industry will have guidance on the scope of typical Composite Protection Systems. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
FirstEnergy Corp	No	None of the Requirements address notifying the Regional Entity on a periodic basis, as is done now (quarterly for RFC). Is it going to be up to the Regional Entity to identify: a. Whether periodic data submittals will be required? b. If so, the periodicity and the template / format for those data submittals? **Response:** The drafting team does not anticipate that Regions actively involved with Protection System operation reviews to end these activities. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[3] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
PPL NERC Registered Affiliates	No	PPL NERC Registered Affiliates comments above for the Slow Trip portion of the Applications Guidelines. A statement should be added, "A Misoperation should not be assumed when the cause of a relay operation cannot be authoritatively established," (reference response to question #3) **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The

[3] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. The discussion of reverse power relays on pg. 26 would be clearer if it included some of the topics and points made in the 2/20/2014 Protection Systems Misoperations Webinar. We propose stating that "The control-vs.-protective demarcation of reverse power relays is based on the operation at hand and not programming". Failure of a reverse power relay to open the breaker at the established time after commencement of motoring is not a Misoperation if using the relay to trip a unit as part of a normal stop sequence. The same failure would be a Misoperation if some unintended event caused the unit to import power. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. The statement on pg. 27, "The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred," should be amended per our comments above for R4. That is, NERC has stated in R4 that determining the cause of a relay operation may take a very long time, and a Misoperation yes-or-no decision may not be possible if the cause for the trip is not known. **Response:** The 120 calendar days is to determine whether or not a Misoperation occurred. The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be

Organization	Yes or No	Question 4 Comment
		found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. Correction is also needed for the flowchart on pg. 35. “A known or possible Misoperation,” should be substituted for, “the Misoperation,” at the top of pg. 29, and elsewhere that this expression is used, because undetermined cause for tripping can make a Misoperation yes-or-no decision impossible. **Response:** The intent of the definition of “Misoperation” and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. The outcome of Requirement R1 or R3 has to be a determination of whether or not a Misoperation occurred. The suggested phrase does not provide additional clarity. Also, the flowchart is intended to provide entities guidance in the relationship between the Requirements within the proposed standard. No change made. The statement on p.29, “certain planned investigative actions may require months to schedule and complete,” should be changed to, “certain planned investigative actions may require months or even years to schedule and complete,” in recognition that generation units are intended to operate for years between planned outages and frequently must be returned to service as soon as possible in the event of a forced outage. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter’s proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision:

Organization	Yes or No	Question 4 Comment
		"certain planned investigative actions may require months **or even years** to schedule and complete," The following statement should be added at the end of the same paragraph, "Taking equipment out of service for the sake of furthering the investigation is not required, and forced outages need not be prolonged for troubleshooting. However, planned outages should include any testing or other actions for which downtime is necessary." The discussion on pg. 30 should include the point that a CAP must be developed within 60 days, but implementing the CAP may take much longer if requiring a downtime opportunity. An example should be included for multiple CAPs under the circumstance of extended troubleshooting, (e.g. taking action for the apparent cause of a Misoperation), developing a new theory and taking different action when the event occurs again several months later and making a final and successful corrective action when the problem occurs a third time. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Dominion	No	a). During the webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples to include: 1. A gas turbine generator has a single reverse power relay which is used to trip the generator breaker during a normal controlled shutdown. This function is considered a control function and not counted as an operation or a Misoperation. 2. The reverse power relay (mentioned in example 1) does not operate to trip the generator breaker and the unit continues to motor until the operator intervenes and opens the

Organization	Yes or No	Question 4 Comment
		breaker manually. Is this a Misoperation? If so what protection system misoperated? Is this considered a Misoperation due to lack of protection? 3. The gas turbine generator mentioned in example 1 and 2 also has a separate reverse power relay that directly trips the generator lockout relay. Is this function considered part of the Protection System? With the unit operating at normal load, this relay incorrectly trips the unit due to an internal relay problem. Is this a Misoperation? 4. A steam turbine generator has a reverse power relay (sometimes referred to as a Sequential trip relay) used in conjunction with valve position switches to trip the generator following a turbine trip. This function is considered a control function and not counted as an operation or a Misoperation. 5. The reverse power relay mentioned in example 4 (sometimes referred to as an Anti-motoring relay) does not operate during a turbine trip and after thirty seconds a second reverse power relay operates as designed to directly trip the generator lockout. Is this second reverse power relay considered part of the Protection System? If so is this counted as one operation that needs to be evaluated? **Response:** The drafting team provided clarification in the Application Guidelines under the section “Control Functions.” Change made. b). Mechanical type breaker trip examples should be expanded to show that air pressure, gas pressure and pole disagreement trips (and their associated auxiliary relays) are control functions and therefore not part of the protection System and thus not subject to this standard. In addition, gas and oil type fault pressure relays on transformers are excluded from Protection System. The example should clarify whether the transformer auxiliary tripping relays (sometimes referred to as 63X relays) are part of the Protection System. Examples could be extremely helpful here since no examples are included in the definition of Protection System.

Organization	Yes or No	Question 4 Comment
		Response: The definition of "Protection System" does not include these types of equipment. No change made. c). Additional Application Guideline examples are needed and the following are specific examples that should be considered: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** The drafting team does not have sufficient information about the TO's breaker tripping to provide a response. 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of its Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and **who is responsible for CAP**, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the highside breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a

Organization	Yes or No	Question 4 Comment
		Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 5. A 230KV line trips at one terminal via its carrier ground relay during closing of a line switch to re-network the line. There was no fault, but the relay operated during typical phase current imbalance created by the poles of the switch closing at different times. Is this a Misoperation? **Response:** This is not a Misoperation based on the information above that the Protection System sensed the prescribed current imbalance and operated correctly. No change made.
Florida Municipal Power Agency	No	FMPA believes it would be beneficial to actually lay out specific failures in the examples. For example, "Slow Trip - During Fault" simply says "A failure of a line's Composite Protection System to operate as quickly as intended for a line fault is a Misoperation." This is more or

Organization	Yes or No	Question 4 Comment
		less a restatement of the definition but applied with the additional detail of a specific protected component (the transmission line). Rather, consideration should be paid to an actual way a relay could fail - for example“...a line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay’s negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element...” most of the nuance in the application comes from the way the relay failed. Another example might be a line fault with electromechanical relays wherein the relay output contacts stuck initially, resulting in a delayed clear. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
SPP Standards Review Group	No	Our preference would be that during a condition of a high number of outages, such as a hurricane or ice storm, we be allowed to request a formal "state of extenuating circumstances" and extend our deadline from 120 days to 270 days. We object to the proposed process where extenuating circumstances can force a utility into a violation and then rely on a nebulous, subjective review to determine whether penalties will be imposed. **Response:** It appears that the comment is objecting to the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, which have been in place for some time. No change made See additional comments on the Applications Guides contained in Question 5 below.
SERC Protection and Controls Subcommittee	No	See #3 in question 2 above.

Organization	Yes or No	Question 4 Comment
		The examples in the Application Guidelines are beneficial, the SERC PCS suggests it would be beneficial to add additional examples and add clarity to who is to report the Misoperation. Some examples are added below. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[4] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. During the recent webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples specific to reverse power. **Response:** The drafting team provided clarification in the Application Guidelines under the section “Control Functions.” Change made. Also, trips should be expanded to show that air or gas system breaker trips or pole disagreement trips are not reportable operations. **Response:** Mechanical systems of a breaker are not included in the definition of “Protection System”. No change made. Additional examples are needed and the following are recommended: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the

[4] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** The drafting team does not have sufficient information about the TO's breaker tripping to provide a response. 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of it's Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the high-side breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** There is not sufficient information to provide an accurate response. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor

Organization	Yes or No	Question 4 Comment
		bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** Yes, this is a Misoperation. An example has been added to the Application Guidelines. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made.
Wisconsin Electric Power Company	No	The examples 8a and 8b under Control Functions should be clarified to help entities make proper distinctions between control functions and protective functions of reverse power relays. We suggest the wording in the paragraph following Example 8b be revised as follows: **Current wording:** In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit. **Suggested wording:** In the examples above, the standard is not applicable because the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System to protect turbine-generators from motoring. Entities often take advantage of this functionality and use the Protection System's reverse power function as a part of a normal procedure to shutdown a generating unit. However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For

Organization	Yes or No	Question 4 Comment
		example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit. **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~red with strikethrough~~ for deletions to illustrate the requested revision: **Suggested wording:** In the example**s** above, the standard is not applicable ~~however, the standard remains applicable to~~ **because** the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System ~~when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operator~~ **to protect turbine-generators from motoring. Entities** often take advantage of this functionality and use the Protection System's reverse power ~~protective~~ function as a **part of a** normal procedure to shutdown a generating unit. **However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit**.
Flathead Electric Cooperative, Inc.	No	I do not believe that UFLS equipment should be included under this standard. **Response:** Currently, underfrequency load shedding (UFLS) is applicable to the proposed standard to close a gap in reliability. No change made.

Organization	Yes or No	Question 4 Comment
LCRA Transmission Services Corp	No	LCRA TSC recommends the SDT address the topic of temporal aggregation within the Application Guidelines. For example, if a transmission line over-trips for an out-of-section fault three times in a 2-hour interval, perhaps due to persistent storm activity before a relay setting adjustment can be made, does this count as three misoperations, or can the three events of a similar nature and cause be “collapsed” into a single misoperation? Some guidance in this area would be helpful in order to allow entities to be consistent in reporting. LCRA TSC recommends some way to collapse/combine misoperation events of a similar nature within a short, defined timeframe. **Response:** The Application Guidelines have been updated to clarify this situation. Change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template. No change made.
American Electric Power	No	1) AEP recommends adding an example to the applications guideline to illustrate whether repeated operations/misoperations which occur during the same automatic reclosing sequence need a separate identification under R1. **Response:** The Application Guidelines have been updated to clarify this situation. Change made. 2) AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a “slow trip” type misoperation. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.

Organization	Yes or No	Question 4 Comment
		3) AEP recommends adding an example to illustrate how breaker failure fits into composite protection system. **Response:** Breaker failure has been clarified in the Application Guidelines under the heading, "Definitions." Change made. 4) AEP recommends adding an example where a misoperation is initially identified, but subsequent investigation (after 120 days) reveals a misoperation did not occur. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Nebraska Public Power District	No	The application guidelines state: "The CAP is complete when all the documented actions to resolve the specific problem (i.e., Misoperation) are completed which may include those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP." In the example R6b it appears the CAP is completed and a program was established for corrections at other locations. Please clarify if a program to address other locations is or is not required to be tracked as part of PRC-004 evidence. In the example, it appears the program for other locations does not need to be tracked for PRC-004 evidence. Is this up to the entity to determine? **Response:** The proposed standard requires that the entity complete a Corrective Action Plan (CAP) for the identified Misoperation. The results of the entity's evaluation of other Protection Systems, including other locations is separate and distinct, and is meant to bring awareness to other areas of potential Misoperation. It is up to the entity's discretion in selecting other locations for evaluation and implementation of any modifications to other Protection Systems. Any action items placed in the CAP (including other locations) are required to be completed. No change made.

Organization	Yes or No	Question 4 Comment
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
Oncor Electric Delivery Company LLC	No	The Extenuating Circumstances process, as outlined on page 32 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the RAI project, Oncor recommends the evaluation of an Extenuating Circumstance be removed from the back end Enforcement phase and up to the Compliance Monitoring phase where the evaluation is done within a risk and controls framework. Furthermore, Oncor recommends the Registered Entity be

Organization	Yes or No	Question 4 Comment
		allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Ameren	No	(1) We request the drafting team add another example to clarify the paragraph on page 26, following Example 8b, which includes "...however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (a) Units in our GO's fleet shut down thousands of times each year, in our opinion Example 8a are applicable. Does the SDT intend to include these as correct operations if indeed the same reverse power relay also provides anti-motoring protection? **Response:** If the BES interrupting device operation is expected as part of a controlled shutdown, the operation is not included per the Applicability section of the standard. The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made.

Organization	Yes or No	Question 4 Comment
		(b) Our protection scheme in some cases will have separate Device 32 elements, with one short and one longer timer; does the SDT intend in these cases that only trips by the longer timer are within PRC-004 scope? GO will need to know as either of these differ from our understanding of NERC SPCS / RAPA guidance for reporting of total operations under the presently applicable PRC-004-2a. **Response:** Both of these 32 devices are part of the generator's Composite Protection System; both are applicable to the standard when operating as a protective function; neither are applicable when operating as a control function. The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (c) Based on the number of reverse power questions on your 2/20/2014 Webinar, it appears to us that many GO's are unclear on your intent. [Generator reverse power reporting clarity is another primary reason for our negative ballot.] **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (2) At the end of Example R4a on page 29, please add "Each of 3/24, 4/10, 5/27, and 8/29 actions are valid investigative actions." If the SDT intends otherwise, please state which ones are valid. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Public Service Enterprise Group	No	The Application Guide is unclear as to the reporting of reverse power relays. A reverse power relay is typically used to remove a generator from service (a control function) AND to prevent generator motoring (a protection function). The two are not separable. On p. 26, example 8a removes the operation of a generator's reverse power relay to open a breaker during routine shutdown from being subject to the standard because it is performing a control function, while the guideline then states "; however, the standard remains

Organization	Yes or No	Question 4 Comment
		applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." If the reverse power relay failed to open the generator's breaker during shutdown, the generator would motor and the breaker would need to be opened by manual intervention. As the SDT may know, reverse power relays have a documented "blind spot" that causes them to fail to operate during low power factor operation of the generator. (We can provide such documentation if desired). For this reason, generator operators normally have procedures with a step that states that the operator is to manually open the generator output breaker if generator the breaker does not open after a predetermined time period. If this occurred, would the failure of the reverse power relay be reported as a Misoperation? **Response:** If the GO includes the manual intervention as part of its process for a controlled shutdown, then it is not a Misoperation. In this case, it has clearly shown it is acting as a control function which is backed up by another control function. As noted, the same relay performs two functions – when the device is performing (or fails to perform) its protective function, that is when it is applicable to the standard. No change made. Finally, per the NERC document "Questions and Answers about Consistent Protection System Misoperation Reporting" dated February 5, 2013, reporting a reverse power relay Misoperation and not reporting a successful operation is inconsistent with the principle stated in paragraph #1 that "if an operation would not count as a misoperation, it should not be included as an operation." Therefore, to avoid further confusion, we recommend that reverse power relays used for equipment shutdown be explicitly eliminated from the scope of this standard. **Response:** Because of the inherent differences in the application of reverse power relays on generators continent-wide, the drafting team has provided the means to exclude them from the set of operations that will be reviewed by entities. The proposed standard's Applicability, Section 4.2.1, states: "Protective functions intended to operate as a control

Organization	Yes or No	Question 4 Comment
		function during switching are excluded."[5] Therefore, operations occurring within the entity's normal controlled process do not fall within the purview of the proposed standard. Any operation outside of an entity's shutdown sequence would be a reviewable operation. No change made.
Consumers Energy Company	No	Generally I agree with the proposed new definition of a Misoperation, but have one hypothetical circumstance where it might be unclear and could perhaps benefit from another example in the guidelines section. Under the category "Unnecessary Trip - Other Than Fault," the guidelines state that an operation that was initiated directly by on-site maintenance...is not a Misoperation. Are there circumstances where on-site maintenance could indirectly cause a Misoperation? We had a situation where a technician was conducting testing on a breaker failure (BF) relay, and accidently initiated the wrong BF relay in an adjacent panel that was still in service and not part of the testing plan for the day, resulting in tripping of the BES bus. Our initial thoughts were that the BF relay should have issued a 'retrip' function to its corresponding breaker after being initiated, thereby only tripping the one breaker instead of the entire bus. Investigation showed the relay was indeed designed to trip the bus and acted properly. BUT if the relay HAD operated improperly after being inadvertently initiated by on-site personnel, would that be a Misoperation? **Response:** According to the example presented above, this would not be a Misoperation due to the exemption in category 6 of the proposed definition. No change made. Does the presence alone of on-site personnel create an exemption in all cases? If that is the case, I think it should be explicitly stated, or another example added to clarify technician-induced operations.

[5] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Organization	Yes or No	Question 4 Comment
		Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Tacoma Power	No	On page 24 of the redlined Application Guidelines, remove the following verbiage: "This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally," This portion does not add value and seems to have a conflicting emphasis with the reminder of the paragraph. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. Regarding Example 4 in the Application Guidelines, Slow Trip - Other Than Fault, equipment damage is not explicitly identified in the definition of a Misoperation. Either the definition should be revised to clearly identify equipment damage or another example should be used that better fits the proposed definition. **Response:** The Application Guidelines (Example 4) has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made.
Southern California Edison Company	No	There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry. **Response:** Thank you for your comment.
Xcel Energy	No	1) The examples for R6 in the Application Guidelines are not clear. In R6a, it states the CAP completed on 6/25/2014, but no action is referenced for this date. In R6b, it states the CAP completed on 10/28/2014 when a proactive only replacement program was established, but

Organization	Yes or No	Question 4 Comment
		in R6c and R6d, the CAP is open until the proactive replacement program is completed. It seems the difference between these two is only semantic. **Response:** The corresponding actions are found in the previous Requirement R5, Example R5a with at date of 07/01/2014. The examples R6c and R6d regarding preemptive replacement have been included in these Corrective Action Plans (CAP) for illustration. An entity may choose to handle other locations either within or separate of the CAP that is remedying the specific Misoperation cause(s). No change made. 2) Please clarify if it was the intent of the drafting team to exclude operations like the following example from being classified as a Misoperation: Assume that a fault occurs in a generator stator, due to either a mechanical or design setting issue the 64S does not operate. However, the 87 does operate and trips the unit. We believe this would not be a Misoperation because of the overall performance of the composite protection system. **Response:** The intent is to provide clarity that a single Protection System component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made.
Hydro-Québec Production	No	For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system. For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team agrees this is a best practice; however, it is not useful having a Requirement for each entity to share information. The way the Requirements are written, it is in the best interest of all parties (i.e., jointly owned Protection Systems) to share or communicate information about operations which meet the criteria for Requirement R1 and

Organization	Yes or No	Question 4 Comment
		R2. Having such a Requirement is administrative and provides little, if any, reliability benefit. No change made.
Indiana Municipal Power Agency	No	It is not clear how an entity is to show that an operation of a BES interrupting device happened fast enough and did not fall into one of the two "Slow Trip" categories of a misoperation. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Florida Power & Light	Yes	The examples are an excellent idea. It would also be advantageous and practical to include supporting information on the scope of Misoperation reporting. Example to consider adding: The boundary of Misoperation reporting extends from protective relay input devices to circuit breaker trip coil(s). **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[6] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. More examples should be provided in relation to Power Generation events. **Response:** The Application Guidelines has been modified as suggested. Change made.
ACES Standards Collaborators	Yes	The examples in the Application Guidelines are improved and provide additional clarity.

[6] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		Response: Thank you for your comment.
ReliabilityFirst Protection Subcommittee	Yes	Other than our suggestion from Question 2, our group would like to state that the concept of the Application Guideline is an excellent tool to retain the thought process behind the development of the standard. Its use in this and future standards will help greatly with the understanding, application, and consistency of the standards. **Response:** Thank you for your comment.
Manitoba Hydro	Yes	(1) PRC-004-3, Application Guidelines, Extenuating Circumstances - for clarity, replace the word “says” with the word “reads”. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Entergy Services, Inc.	Yes	Look at response to question one. **Response:** Thank you for your comment.
Exelon	Yes	The concept of the Application Guideline (AG) is an excellent tool to retain the thought process behind the development of the standard. Use of an AG in this and future standards will help greatly with the understanding, application, and consistency of the standards. Generally, the applications are sufficient for the purpose. Specific comments for clarification include: In “Unnecessary Trip - Other Than Fault”, in the paragraph after Example 6d, the “on-site” maintenance activities section needs more clarity. Is the intent of that paragraph trying to say, if the BES Protection System equipment clearly misoperated and personnel had nothing to do with it, then it’s a PRC-004 misoperation. If the BES Protection System equipment appeared to misoperate, but it’s clear that personnel had something to do with that operation, it’s not a PRC-004 misoperation?

Organization	Yes or No	Question 4 Comment
		Response: This is correct and for the example above, both of these points are described in the Application Guidelines in the paragraphs preceding and following Example 6e. No change made. For a Communication System, does the "on-site" activities exemption apply to anywhere along the communication path were personnel caused what would otherwise look to be a BES Protection System misoperation? **Response:** According to the example presented above, this would not be a Misoperation due to the exemption in category 6 of the proposed definition. No change made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company;	Yes	

Organization	Yes or No	Question 4 Comment
Southern Company Generation; Southern Company Generation and Energy Marketing		
Virginia State Corporation Commisison	Yes	
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	
PJM Interconnection	Yes	
Muscatine Power and Water	Yes	
American Transmission Company	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
TransÉnergie Hydro-Québec	Yes	

Organization	Yes or No	Question 4 Comment
Northeast Utilities	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Cowlitz PUD	Yes	
ITC	Yes	
Liberty Electric Power LLC	Yes	

5. **If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:**

Summary Consideration: There were a number of comments that were relevant and consistent with responses found in the previous questions above and will not be summarized here. The most notable majority comment that resulted in a change was the Implementation Plan. The previous allowance of 24 months for the standard to become effective in the Western Interconnection was changed back to 12 months. This was changed because it was determined that a conflict does not exist between the proposed continent-wide PRC-004-3 and regional PRC-004-WECC-1 standards. Also, implementing the standard on the same time basis continent-wide eliminates any perceived preferential treatment. Minority comments included a number of editorial suggestions and edits which the SDT implemented.

The following summarizes comments which did not result in a change. One majority theme came from three comments supported by 22 individuals that had concerns about the population of BES interrupting device operation events that would be audited. The SDT noted that only those operations that meet the Requirement R1 criteria (i.e., 1.1, 1.2, and 1.3) are to be reviewed to identify whether a Misoperation occurred or not. The Reliability Standard Audit Worksheet (RSAW) also supports this approach and intent. Notable minority comments include approximately nine individuals that were concerned about timeframes, milestones, or closure of a CAP. The SDT responded that timeframes are needed to make the Requirement measurable and the CAP is closed by the entity based on its timetable. The commenters were concerned that the Regional Entities will no longer be involved with ensuring entities follow through on completing CAPs. Eight individuals were concerned about the cases where a Generatfaor Owner operates the Transmission Owner's BES interrupting device. The SDT noted that communication would need to occur and does occur today. Most of the BES interrupting device operations would be a result of synchronizing to the BES or a normal shutdown through a control function to remove the generating unit from service, both are not reviewable operations under Requirement R1. Approximately six individuals believed that Requirement R2 (i.e., "notification") is administrative and qualifies under the Paragraph 81 (P81) criteria as having little reliability benefit. The SDT contends that Requirement R2 has a reliability need to involve other owners that may need to review their Protection Systems for possible Misoperation. Approximately two comments supported by seven individuals argued that "manual intervention" in Requirement R1 is unnecessary because it is rare and should be requested by an auditor by exception. The SDT agrees that such situations are probably rare; however, the SDT contends this is a valid condition for which an entity must be required to identify any possible Misoperation of a BES Protection System. Last of the majority comments include four individuals that expressed concern over the Violation Severity Levels (VSL). Commenters were concerned about VSLs being unjust for larger entities. The SDT noted that the NERC VSL Guidelines were adhered to and do not unjustly impact larger entities. VSLs only come into scope during a potential violation, are per event, and not based on the size of an entity; therefore, are size-neutral.

Notable minority comments which did not result in a change include a request to add a field to the data request for reporting Misoperations, being clear the standard is not requiring Disturbance Monitoring Equipment (DME), and underfrequency load shedding (UFLS) only for BES Elements. The SDT provided feedback to NERC staff concerning the additional data request field for reporting. Also, the SDT contends that the standard and Application Guidelines provide the necessary points that DME is not required and that UFLS for BES Elements addresses the reliability concerns adequately.

Organization	Question 5 Comment
TransÉnergie Hydro-Québec	An addition "Field" can be added to improve metric analysis of microprocessor relays malfunction since these are the type of relays that will be installed in the future by every entities. As the number of microprocessor continue to grow, the more frequent will a Misoperation be caused by these type of relays, therefore this added field would greatly improve metric analysis. For example, the Field Value for a microprocessor relay malfunction could include the following: Setting Error - Incorrect Numerical Input Specified Setting Error - Incorrect User-Programmed Custom Logic Incorrect Design - Incorrect User Application Incorrect Design - Wiring Firmware Version Mismatch by User Others. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[7] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
Cowlitz PUD	Applicability section 4.2.2 includes UFLS only if it trips a BES element. We believe that UFLS inclusion in this standard should only be applicable to those single UFLS elements that can have an adverse impact to the BES. Limiting applicability to UFLS elements which trip a BES element will not adequately address all UFLS adverse impact elements. For example, some industrial loads must be shed in a carefully planned sequence, and it may not be possible to link the UFLS trip signal to a BES element. Instead, the trip signal is received within the

[7] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

	industrial load (plant) whereby a controlled plant shutdown is automatically initiated. This load shedding can exceed 200 MW, and is significant. In such UFLS schemes, the actual process of the load shed within a non-BES plant should not be subject to standard compliance; however, the misoperation of the associated UFLS relay as a single point of failure should be considered as a significant BES support device. Inclusion of UFLS in this Standard may be duplicative of PRC-006-1, requirements R11, R12, and R13. An underfrequency event is generally a system wide event; conversely, the objective of Protection System action is to isolate an event to prevent it from becoming a system wide impact. UFLS elements must work as a coordinated system which can withstand several UFLS element failures, yet successfully stabilize the BES. Since PRC-004-3 addresses discovery of problems after an event, we propose that at best this Standard would assure UFLS element Unnecessary Trip misoperations would be mitigated. The discovery of a UFLS element Failure to Trip which has an adverse impact on the ability of the UFLS system to stabilize the BES as stated above is addressed by PRC-006-1. Notwithstanding the above, we do not see our concerns as requiring a negative ballot. **Response:** The drafting team contends that addressing underfrequency load shedding (UFLS) for Bulk Electric System (BES) Elements provides the necessary applicability for reliability. A UFLS relay that trips non-BES equipment (i.e., customer load or distribution) is a quality of service issue for the entity's customers and the impact on BES reliability is not measurable. The standard PRC-006-1 addresses UFLS program performance and will reveal potential Misoperations when evaluating the program's performance to a frequency excursion. Only UFLS relay operations directly impacting BES Elements need be included within the applicability of the proposed standard PRC-004-3. No change made.
Ameren	(1) Delete from R1 1.1 "or by manual intervention in response to a Protection System failure to operate;" and remove from Rationale for R1, and Process Flow Chart. This is an extremely rare occurrence not warranting special inclusion in the requirements. In our view, manual intervention is already included in that Failure to Trip is a Misoperations and a BES interrupting device did operate, albeit manually. It is acceptable to retain some mention or explanation of it in the Application Guidance to keep it from falling out of the consciousness. Unnecessary Trip - During Fault on page 24 already points out the correct remote clearing that would occur for a Fault. [Unwarranted inclusion of 'manual intervention' in a Requirement is another primary reason for our negative ballot.]

	Response: The requirement is written so that only manual interventions in response to a Protection System failure are required to be identified in addition to automatic operations of a Protection System. No change made. (2) Please add "Note: Historically, the cause of about of 10% NERC-wide Misoperations have an unknown cause" at the end declaration paragraph (2nd last paragraph) on page 29. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (3) On page 31, please add "For completion of the CAPs in examples R5a through R5d see examples R6a through R6d on pages 33 and 34. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (4) We understand R1 to apply to the aggregate set of BES interrupting device operations associated with the same BES event (e.g., fault, abnormal condition, etc.) For example, under present NERC SPSC guidance the entity count all trips in the automatic reclose cycle and reports them as a single event. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (5) The NERC PSMTF Final Report recommended grouping all like events involving the same Protection System within a 24 hour period, recognizing that the response time limitations to altering the Protection System. SERC PCS advocated the 24 hour grouping in our comments to NERC on the Section 1600 Data Reporting draft. The resulting metrics more clearly indicate dominant causes, rather than being distorted by repetitive like events on the same Element and Protection System. **Response:** Please see the Application Guidelines, on multiple operations/same event/automatic recloses. Change made. (6) If the SDT intends that each and every BES interrupting device operations be separately tracked, the TO, GO, and DP certainly need to know this. Although every breaker operation is almost always available within the SCADA log attached in our PRC-004 software database, we group them into a single event record

	in accordance with applicable NERC guidance. We are concerned that if R1 intends we have a separate event record for each breaker operation, the administrative overhead is unwarranted and burdensome. **Response:** Please see the Application Guide under the heading "Requirement R1." The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list." The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. No change made.
Texas Reliability Entity	(1) For Requirement R5, how does the SDT intend to handle a situation where the CAP involves another registered entity. For example, we've seen several cases where the CAP requires multiple TOs to make setting changes in order to mitigate the cause of the misoperation. In this case, should both TOs involved have their own CAP? **Response:** The entity whose Protection System component caused a Misoperation is required by the proposed standard to develop and implement a Corrective Action Plan (CAP). Part of the action within that CAP may include coordinating work such as settings with other entities. Coordination of settings also falls under the current Reliability Standard PRC-001-1 – Protection System Coordination. No change made. The requirement language is not clear. The bullet "Explain in a declaration why corrective actions are beyond the entity's control..." provides no assurance that all the required actions to mitigate the Misoperation are completed in cases where multiple entities are involved in the CAP. **Response:** Requirement R4 of the proposed standard is providing a mechanism for entities not to make corrective actions when such actions are not practical and will not improve reliability. See Examples R5e and R5f in the Application Guidelines. No change made. (2) Evidence Retention: We recommend changing the evidence retention from 12 months to a minimum of 3 years.

	Response: The drafting team based data retention on guidance provided by NERC staff for writing evidence retention periods. See pages 8 through 14 of the NERC Background Information for Quality Reviews, February 7, 2012 for more information.[8] No change made.
Manitoba Hydro	(1) R4, second bullet - for consistency with the previous bullet, rephrase to read "A declaration that no cause(s) were identified." **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (2) R5, second bullet - because it's possible that a single corrective action can be taken, add brackets around the "s" in the word "actions". **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (3) R6 and M6 - for consistency with other requirements in the standard, replace the word "actions" with "corrective action(s)". **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (4) R1 and R2 a. Use of the past tense (i.e. "that operated") is inappropriate for statutory / regulatory standards. The wording should be: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device shall, within 120 calendar days of the operation of the BES interrupting device...". **Response:** Without the phrase "that operated" all BES interrupting device owners would have to investigate every BES interrupting device operation. No change made. b. Similarly, in R2.2 and 2.3, the word "determined" should be replaced with "has determined".

[8] http://www.nerc.com/pa/Stand/Resources/Documents/BackgroundDocument.pdf

	Response: Change made. c. Use of the word "when" implies a time frame. Given the intent, it would be clearer to use the phrase "under the following circumstances". **Response:** Change made. (5) R5 - for the reasons identified above, the use of past tense should be changed to:" Each Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System Component that causes a Misoperation ...". **Response:** The use of "caused" is used to emphasize that the Misoperation has already been identified in the previous requirements. No change made. (6) The wording of R6 makes the compliance obligation unclear. Part of the requirement requires implementation of a CAP. However, another part of the requirement allows updating and changing the CAP. Accordingly, it can be inferred that some deviation from the CAP, and thus failure to implement the CAP, will still be considered compliance. A review of the Application Guidelines also confirms that rescheduling actions under the CAP is permitted in at least some cases. The criteria for acceptable revisions should be clarified in R6 (ex.- do they need to be beyond the reasonable control of the Responsible Entity?). **Response:** The Application Guidelines provide three examples of situations where reliability would not be improved. Requirement R5 addresses two situations where a CAP does not need to be developed and a declaration will be made. The definition of "CAP" limits the scope of the remedy to a specific problem; therefore, the drafting team contends that it is unlikely to be impractical to implement a CAP. No change made. Manitoba Hydro has concerns with the lack of clarity of Misoperation definition. Manitoba Hydro believes that the definition of Misoperation needs to be re-written for various reasons specified in the comments. **Response:** See responses in Question 1. For R4, Manitoba Hydro recommends the removal of the investigation frequency as repeated investigative actions would not be productive in identifying the cause of a Misoperation.

	Response: The proposed Requirement R4 provides the entity discretion on how to handle ongoing efforts. At least one investigative action is required toward determining the cause(s) of an identified Misoperation. Beyond that, the entity may declare it is unable to determine the cause(s). Whether the investigation is held open in anticipation of capturing similar operations, or if closed with a declaration, the entity should have the pertinent information documented both for future reference and compliance with the Requirement(s). No change made.
ACES Standards Collaborators	(1) We are concerned that Part 1.1 may cause an auditor to request an inventory of all BES interrupting device operations. From that list, then the applicable entity would be required to identify which BES interrupting device operations were cause by Protection System actuation and which were operator interventions. Then, the applicable entity may have to prove each BES interrupting device operation initiated by an operator was not necessitated by a Protection System Misoperation. Also, the applicable entity would have to show for each BES interrupting device operation caused by Protection System actuation was evaluated for Protection System Misoperation. **Response:** The drafting team structured the criteria in a manner to be clear that the audit population of BES interrupting device operations is those operations which meet the three criteria 1.1 through 1.3. This is further noted in the accompanying rationale box for this and the previous version of the proposed standard. The posted draft RSAW developed by NERC Compliance supports this approach. No change made. While we understand that an applicable entity will have to show it evaluated each BES interrupting device operation caused by a Protection System operation, we do not believe they should be required to identify those operations caused by other means such as a manual operation by the operator. To identify cases where manual intervention was necessary due to a Protection System misoperation, the applicable entity should be able to rely on its operator notifying the protection systems department that such actions were necessary. In other words, Part 1.1 should be evaluated based on this exception with the auditor only requesting the applicable entity to identify the instances where manual intervention was necessary. An explanation in the Application Guidelines for what is required here would be helpful.

	Response: The requirement is written so that only manual interventions in response to a Protection System failure are required to be identified in addition to automatic operations of a Protection System. No change made. (2) Requirement R1 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the entity "to identify whether its Protection System component(s) caused a Misoperation." If an entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the requirement. By definition, the Distribution Provider cannot own a "BES interrupting device" since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the Distribution Provider to apply. **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. No change made.

	Response: The drafting team agrees that a Distribution Provider (DP) which owns Bulk Electric System (BES) interrupting device should be registered as a Generation Owner or Transmission Owner (TO) as the case may be. However, in this case, the DP may own a non-BES Protection System which operates a BES interrupting device. This is why the drafting team has included the DP as an applicable entity. No change made. (4) For the second severe VSL of R3, "a Misoperation its Protection System" should be "a Misoperation in its Protection System." The "in" is missing. **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (5) We disagree with the VRFs for R2. It is an administrative requirement and should not even be a requirement since it meets P81 criteria. However, if the requirement persists, the VRF should be no higher than "Low" since it is administrative. **Response:** Requirement R2 is not purely administrative since without a mandatory reporting to other owners as defined in R2, there is no expectation of performance by the other owners as prescribed in Requirement R3. No change made. (6) Thank you for the opportunity to comment.
MRO NERC Standards Review Forum	: The NSRF is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. The NSRF also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due

	to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
SERC Protection and Controls Subcommittee	1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device becomes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made. Requirement R2 was revised to address the case where an entity's BES interrupting device provided backup protection. Part 2.2 of Requirement R2 requires this entity to notify the entity that backup protection was provided which is most likely due to a failure to operate. Change made. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. 3. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However,

	if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. 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.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device comes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made. The drafting team contends that the "failure of a Composite Protection System to operate for a Fault" provides sufficient guidance to determine if a "Failure to Trip" occurred. The operation of other zones to prevent the event from propagating should be considered along with the other available evidence. No change made. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP.

	Response: The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each TOP and GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. Note: related to above 3 comments: Although the recently posted RSAW mitigates some of these concerns, we feel the Standard itself should be modified to go back to the concept of 'BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation' thus removing the need to include the TOP in the applicability. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. 3. The various timetables introduced in the Standard result in many compliance milestones to be tracked for minimal if any overall increase in reliability. There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. **Response:** The time periods in the standard are maximums for completing work relative to each Requirement and the drafting teams contends they are reasonable. Dates should be included in the entity's evidence of completion for each Requirement. The only exception to this is demonstrating the investigative actions in Requirement R4 which occur on a periodic basis. This time period is essentially six months and is minimal for the overall number of unidentified causes that go beyond the initial 120 calendar days from the operation of the BES interrupting device. No change made.

	4. We also observe that the Standard does not require any closure on a specific event. As noted in R6: implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. Therefore, an acceptable CAP could be 'we plan on upgrading the protection systems in 15 years which will solve the problem'. Since the neither proposed actions nor timetable may change, no update is required. This seems to contradict the statement in the Rational box for R6 which states: Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion. **Response:** The example provided is not practical nor is it consistent with the definition of Corrective Action Plan (CAP) and the examples provided in the proposed standards' Application Guidelines for both Requirement R5 and R6. No change made. 5. Related to comment #4 above, which notes that there is no requirement for closure: Recognizing that there has been considerable work by various NERC teams (SPCS, RAPA, and the PSMTF) to implement consistent reporting utilizing the misoperation template and that one of the recommendation was that the Regional entities need to become closely engaged in reviewing submittals and following up on action plans/ corrective actions; we would encourage the SDT to consider revamping the Standard to require the quarterly submittal of misoperation data utilizing the approved template and NERC and the Regions to agree on some standard methodology for Regional review and follow-up if progress is not being made. **Response:** The effectiveness of a CAP would be apparent in the number of recurring events of a similar nature. It is expected that entities would seek solutions for Protection System Misoperations that prevent recurrence. The drafting team understands when the patterns of Protection System Events indicate increasing recurring events of a similar nature there is value in having Corrective Action Plans (CAP) reviewed by others and in some cases the Regional Entities are currently performing these activities. Also, a Reliability Standard Requirement cannot be applicable to the Regional Entity; therefore, this entity would not be mandated to do such reviews. The drafting team expects that entities will facilitate reviews of Protection System operations, Misoperations, and/or CAPs this through peer review groups or industry forums. No change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data

	submittals and the associated template.[9] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
Tri-State Generation and Transmission Association, Inc.	1. The standard is difficult to interpret regarding jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. An interrupting device and all or part of the Composite Protection System may be owned by a contractually-organized group that is not a registered Functional Entity. This makes it unclear which entity is responsible for initial review and potential notification under Requirement R1. Our belief is that it would be the registered entity that is contractually responsible for operating the interrupting device. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. 2. It is also unclear whether Requirement R2 includes notice to all the other joint-owners of the Protection System or only to the owners of the Protection System components that are not owned by the joint group. Our belief is that notice should only be given to the owners of the Protection System components that are not owned by the joint group. Our proposal to eliminate the uncertainty is to add a statement to the Applicability that addresses how jointly-owned Facilities are to be handled in the standard any time a TO, GO, or DP has a responsibility. **Response:** The standard requires notification to the other owner(s) when a Misoperation occurs or cannot rule out a Misoperation and the owner's Protection System component did not cause the Misoperation. There is no exclusion for components that are owned by multiple discrete entities. The challenges of delineating compliance responsibility for contractually joined entities would be extremely difficult and outside the scope of Standard Drafting Team. No change made.

[9] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Puget Sound Energy	a) Under Facilities on p.5, UFLS /UVLS should both be listed, if intended. The order of facilities (specifically content of 4.2.1 and 4.2.2) should be swapped - so that everything INcluded comes before everything EXcluded. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. b) There should be a whole section clarifying exclusion of SPS/RAS (but inclusion of UFLS/UVLS). Or....the definition of SPS/RAS should be changed to include UFLS/UVLS. **Response:** The Background section states "Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities." Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. c) A Misoperation Process Benchmark table of reporting functions and dates should be provided to entities. This would greatly facilitate retention of misoperation timeline evidence (for audits, self-cert, data requests). The Misoperation Process Benchmark table structure could be provided by the Regional Entities such as WECC in an updated misoperation Criterion as an Appendix. A suggested list of Benchmark dates is as follows: 1. date of Interrupting device operation, 2. date of identification of misoperation, 3. date other owners of Protection System (of BES interrupting device operation) notified, 4. date of identification by notified entity whether its device caused a misoperation, 5. date the cause of misoperation investigated/found,

	6. date of further investigation (if cause not found) 7. date of Corrective Action Plan (CAP) development 8. target CAP completion date(s), actual CAP completion date **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[10] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. The drafting team has forwarded your suggestion to the appropriate NERC staff for consideration. No change made. d) Finally, it is recommended that Quarterly Misoperation Reporting be changed over to a "Data Request" sooner than the effective date of PRC-004- **Response:** The drafting team agrees that in theory this sounds like a good idea; however, Regional Entities and NERC may need the allotted implementation period to address changes in data collection and practices that will be effectuated by the proposed standard. This is especially true with NERC developing the systems for collecting data rather than the Regions. No change made. 3. It is stated on page 5 of the proposed PRC-004-3, that the currently reporting system is "not optimal to establish consistent metrics for measuring Protection System performance". Perhaps the ERO Reliabililty Assessment and Performance Analysis Group could release an updated recommendation letter for Misoperation Reporting. It is also recommended that the Misoperation "Data Request" occur once per year. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[11] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.

[10] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

[11] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Northeast Power Coordinating Council	a. The "Effective Dates" section of the standard is confusing as it suggests no regulatory (i.e. FERC) approval is required in Western Interconnection and offers both twelve and twenty-four month timeframes. **Response:** After further review and discussion with WECC following the latest changes to the standard, the proposed standard and the existing regional standard do not conflict. Therefore, different implementation timeframes are no longer necessary. However, the language used in the implementation plan is the stock language NERC uses for effective dates of Reliability Standards. In the prior version of the implementation, the effective dates were specified separately for WECC to provide time to eliminate language conflicts between the proposed standard and the regional standard. Since no conflict exists, there will be a single effective date for the standard. Change made. b. Applicability Section - Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs a similar function when initiated by abnormal voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. c. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. **Response:** The Measures have been updated. Change made. d. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a

	Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. e. VSL for R3: Second condition under SEVERE - similar comment as for the VSL for R1 preceding. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. f. The SDT should reconsider the need for the defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. The comment report indicated that 4 commenters representing 24 individuals requested clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing the redundant new term. **Response:** The reason for proposing the newly defined term, "Composite Protection System," is found in the Application Guidelines under the heading "Definitions." No change made.
Independent Electricity System Operator	a. Applicability Section - Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs similar function when initiated by voltage conditions. The draft standard does

	not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. b. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. **Response:** The Measures have been updated. Change made. c. Measure M2: Similar comment as for M1, above. The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. **Response:** The Measures have been updated. Change made. d. Measure M3: Similar comment as for M1, above. The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. **Response:** The Measures have been updated. Change made. e. Measure M4: Similar comment as for M3, above. The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. **Response:** The Measures have been updated. Change made.

	f. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. g. VSL for R3: Second condition under SEVERE - similar comment as for VSL for R1, above. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made.
American Electric Power	AEP believes the draft is very close to being ready for final ballot. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. Our negative vote does not reflect disagreement on the direction or intent of the standard. Rather, it is driven by a number of smaller issues that, in total, would prove problematic in consistently applying the standard. **Response:** Thank you for your comment.
David Kiguel	As written, the draft standard leaves a void that should be filled. A mechanism must be provided to allow for verifying that the conclusions of the investigation are correct, the CAP is appropriate and overseeing its completion within the planned time.

	Typically, this would be a responsibility that could be assigned to the Reliability Assurer (RA) as defined in the BoT approved Functional Model. The FM definition of RA fits this role well. However, since no entities are registered as RA at this time and it is unlikely there will be in the future, a second choice would be assigning such responsibility to the Planning Coordinator (PC). Suggest adding an additional requirement assigning such responsibility to the RA (or the PC if the SDT decides so): Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall submit its investigation report and CAP documentation to the Reliability Assurer (or Planning Coordinator) that has responsibility for the area in which the associated devices are located, within 21 calendar days of their completion. The RA (or PC) shall review and either approve or provide comments within 60 calendar days of the submission. **Response:** The drafting team understands the value of having Corrective Action Plans (CAP) reviewed by others and Regional Entities. However, a Reliability Standard Requirement cannot be applicable to the Regional Entity The Planning Coordinator does not have the expertise to review these CAPs. No change made.
CenterPoint Energy Houston Electric LLC	CenterPoint Energy recommends revising the wording of the second bullet of Requirement R5 to account for situations where corrective action would not be practical. CenterPoint Energy suggests the following wording: 'Explain in a statement why corrective actions are beyond the entity's control or would not improve BES reliability or may not be practical, and that no further corrective actions will be taken.' **Response:** The Application Guidelines provide three examples of situations where reliability would not be improved. Requirement R5 addresses two situations where a CAP does not need to be developed and a declaration will be made. The definition of "CAP" limits the scope of the remedy to a specific problem; therefore, the drafting team contends that it is unlikely to be impractical to implement a CAP. No change made.
Xcel Energy	Definition for Unnecessary Trip - Other Than Fault: The first sentence of this is unclear (triple-negative) without the expanded language in the Application Guidelines section. Consider omitting the clause "...for which it is not designed" to make this more clear.

	Response: The drafting team removed the "for which it is not designed" language. Change made. The analysis of a Failure to Trip situation does not appear to be covered here, except to the extent that another interrupting device trips in a different zone to prevent the event from propagating. **Response:** Requirement R2 has been modified by adding Part 2.2 to address these concerns. Change made. The drafting team contends that the "failure of a Composite Protection System to operate for a Fault" provides sufficient guidance to determine if a "Failure to Trip" occurred. The operation of other zones to prevent the event from propagating should be considered along with the other available evidence. No change made.
SPP Standards Review Group	Exclusions for SPS and RAS are mentioned in the Rationale Box for Applicability. If these exclusions are not incorporated in the RSAW, which was just recently posted and we have not had a chance to review, then the exclusions should be included in the applicability section of the standard. **Response:** Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. Typos/grammatical/editorial: In the last line of the 4th paragraph on Page 5 under the Background section, insert 'be' between 'to' and 'independent'. Insert 'of' in both portions of the Moderate VSL of R5 between 'days' and 'first'. Application Guidelines In the definition of Composite Protection System on page 21, change the 'a' in front of 'Element' to an 'an'. In the 1st paragraph under Requirement R1 on Page 27, delete the 'that' following 'identified' in the next to last line of the paragraph. In Example R2a under Requirement R2 on Page 28, set the phrase 'or DCB relaying' off with commas. In the last line of the last paragraph under Requirement R3, insert an 'as' between 'such' and 'an'.

	In the 2nd line of the 1st paragraph under Requirement R4 on Page 28, delete 'the entity' following 'notified,' in the 2nd line. It would be helpful to include the initiating event in Examples R4b and R4c.Hyphenate 'in-service' in the 3rd line of Example R4c on Page 30. In the 1st paragraph under Requirement R5 on Page 30, delete the 'or' and place parentheses around CAP in the 2nd line. Reword the 1st line of the 3rd paragraph under Requirement R5 on page 30 to read: 'The time periods within Requirements R1, R3 and R5 are distinct...' On Page 31 in the introductory paragraph for Examples R5a, R5b and R5c, insert 'in the relay' in the 2nd line of the paragraph following 'capacitor'. Also, in the examples, rewrite the sentence that states 'Replace capacitor.' to say 'Replace the capacitor.' We suggest the introductory paragraph for Examples R5g, R5h and R5i on Page 32 be rewritten to state: The following are examples of a declaration why corrective actions would not improve BES reliability.' In Example R5i on Page 32, spell out POTT. In Examples R6a, R6b and R6c on Pages 33 and 34, change the sentence in the 2nd line of both examples from 'The failed capacitor...' to 'A failed capacitor...' Delete the semicolon in the 2nd line of the last paragraph on Page 33. To eliminate any possible confusion, change the CAP completion date in Example R6c from 03/09/2015 to 03/01/2015. The example gets messy if the completion date is actually after the scheduled completion date. **Response:** The above suggestions have been addressed. Changes made.
FirstEnergy Corp	For FirstEnergy, the "BES interrupting device" (GCB or Generator Circuit Breaker) is typically owned by the TO, due to the location of the POI (Point of Interconnection). However, the Protection System devices which operate the GCBs are owned by the GO. Regardless the ownership, the GO certainly knows when the "BES interrupting device" (GCB) operates. It appears that a significant emphasis of this revision is to

	ensure the owner of the BES interrupting device and the owner of the Protection System devices which operate the BES interrupting device are communicating and collaborating in the evaluation. It would seem that the detailed effort to ensure this provides more confusion than clarification for the GO. **Response:** While the situation provided is not uncommon, there are far more cases involving TO-TO interconnections where a clear understanding of accountabilities is required. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	ICLP is concerned that Compliance Enforcement Entities' interpretation of PRC-004-3 will evolve over time - particularly as new Protection System vulnerabilities are found through the evaluation of Misoperations. In addition, the need for greater numbers of measuring points and the increased granularity of Disturbance data will naturally grow as relay schemes become more and more complex. This means that a clear expectation of the requirements for Disturbance Monitoring Equipment (DME) must be established up front in a binding fashion. We accept the project team's assertion that PRC-002-2 (presently under development) is the proper vehicle for the identification of required DME locations, but would like to see a clear tie to PRC-004-3. Otherwise it is easy to see that CEAs may decide at a future date that Misoperations' reporting needs are the driving factor for DME, not PRC-002-2. **Response:** The standard does not require the use of DME to determine whether a Misoperation has occurred; however, if DME are available, then they can be used to make the determination. The drafting team contends that PRC-004-3 does not require the installation of DME to assess interrupting device operations. No change made.
Florida Municipal Power Agency	In general, FMPA disagrees with the philosophy of the current standard. Protection system design is too complex, too diverse, and requires too much engineering judgment to be conducive to making all system designs and voltage classes of systems fit into one set of criteria. Many of the comments the PSM SDT has been receiving are evidence to that effect. System Protection is just as much an art as it an engineering science (i.e., "The Art and Science of Protective Relaying", C. Russel Mason, Wiley, 1956). FMPA supports the intent of the statements that the SDT has laid out which seek to provide the individual entities with the ability to provide engineering judgment, but there is no clear cut way to establish measures and allow entities to demonstrate compliance without a set of specific criteria against which the comparison can be made. Thus, FMPA believes entities should have "Protection System Design Philosophies" for their systems as appropriate, analogous to the FAC-008-3 and the prior FAC-008-1 and 009-1 standards and facility Rating

	Methodologies. Entities can lay out the characteristics of their systems - what is the “intended operation” for the systems, and what, generically, constitutes the constraints around which that entity develops its Composite Protection Systems. We recognize the tremendous amount of work the PSM SDT has put forth in attempting to reach industry consensus on this document but do not believe any form of document that applies criteria without a corresponding philosophy behind that criteria makes the standard too ambiguous. In recognition of the art of protective relaying, we suggest documenting a protection philosophy and intended operation of systems against which to measure whether a protection system operates as intended or not. **Response:** The drafting team contends “operate as intended" is illustrated by the Misoperation definition. An Element's total complement of protection needs to operate dependably and securely. The Application Guidelines has been revised to add clarity concerning this issue. Change made.
Nebraska Public Power District	It seems like the scope for the CAP that must include an evaluation of other Protection Systems including other locations to be completed is very open ended. The concern is what an audit team’s latitude will be with reviewing and accepting or not accepting the subjective nature or these evaluations for other locations. Can the SDT comment how an evaluation that was completed for other locations as part of a misoperation might be addressed in an audit? For example, if a misoperation occurs due to a setting error and an entity decides not to review every relay setting on their system is it possible for an audit team to disagree with this evaluation and create any potential violations? **Response:** The drafting team is not in a position to state how an audit team may or may not determine compliance; however, the draft RSAW available on the NERC web page for this standard may be helpful in answering these types of concerns. The Application Guidelines provide guidance to the extent of evaluating other locations. No change made. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations.” **Response:** Yes, guidance is provided in the Application Guidelines under section heading “Requirement R4.” No change made.

	It is recommended the section 1600 Misoperation Draft Template language should match PRC-004-3. It would be quite odd to have the evaluations requirements and a data submissions request use different language. **Response:** The data reporting was split off from the standard, in part, to provide flexibility to make changes to the reporting template as needed to further the analysis of Misoperations. Therefore, the drafting team cannot guarantee that the reporting template will match the standard. The portion of R6 that states "and update each CAP if actions or time tables change, until completed" seems excessive and granular in nature and adds a lot of detail tracking and difficulty in auditing. It is enough to require a corrective action plan be implemented and close the plan when the final objectives are completed. R4 provides the long term tracking and scheduling. This portion of R6 should be removed. Another option would be to use similar language as in R4. **Response:** Requirement R4 requires determining the cause of the Misoperation, but does not involve a CAP. Requirement R5 requires developing a CAP. The language you reference in Requirement R6 is included to give an entity leeway to revise their proposed corrective actions or timetables if new developments or unforeseen circumstances warrant. No change made.
Muscatine Power and Water	MP&W is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. MP&W also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.

JEA	R1 & R3 both need an exclusion for any declared natural disasters. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made. We also believe that the 60 day timeframe identified in R5 to develop a Corrective Action Plan and evaluate applicability is not sufficient to consider applicability to other PS, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. We recommend this be changed to 180 days. **Response:** The drafting team believes that 60 days is sufficient to develop a CAP including its applicability to other Protection Systems as there is opportunity to update the CAP in Requirement R6 as needed. The drafting team believes that issues such as cost/benefit scenarios, resource coordination, scheduling, and funding procurement can be considered while developing the schedule of the CAP. No change made.
US Bureau of Reclamation	Reclamation thanks the drafting team for their efforts refining the standard and providing the examples in the Application Guidelines. **Response:** The drafting team thanks you for your comment.
Entergy Services, Inc.	Required Protection System Misoperation identification and evidence in support of R1 could be interpreted to include all scheduled or manual interrupting device operations, which we believe is not and should not be the intention. Either way, suggest rewording R1 to include the applicable Protection System governing criteria by integrating R1.1 (revised) into requirement R1 as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated due to a Protection System operation or a Protection System failure to operate

	as designed shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when:" **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made.
Tacoma Power	Since Protection System operations that are related to (or caused by, if this verbiage is retained) on-site maintenance, testing, inspection, construction, or commissioning activities are by definition not Misoperations, is it necessary under Requirement R1 to document that the entity identified "whether its Protection System component(s) caused a Misoperation" for these cases of Protection System operations? BES interrupting devices may be operated many times during on-site activities from a Protection System, or part of a Protection System, and it would be very burdensome to document actions taken surrounding this activity for purposes of compliance with PRC-004-3 Requirement R1. Consideration should be given to an additional part under Requirement R1 such as the following: "The BES interrupting device operation was not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities." **Response:** The operation of out-of-service equipment is not applicable to the standard. If the operation of the Protection System causes the operation of an in-service BES Element, it must be evaluated irrespective of on-site activity. Additional information is provided in the Application Guide under Requirement R1 (last paragraph). Change made. Regarding the Severe VSL for Requirement R3, change "...whether or not a Misoperation its..." to "...whether or not a Misoperation of its..." (This also needs to be updated in the VRF/VSL Justification.) **Response:** The language has been changed. Regarding the Moderate VSL for Requirement R5, change the two instances of "...calendar days first..." to "...calendar days of first..." (This also needs to be updated in the VRF/VSL Justification.)

	Response: The language has been changed. On page 32 of the redlined VRF/VSL Justification, in the FERC VRF G3 Discussion, change references to 'VSL' or 'VSLs' to references to 'VRF' or 'VRFs' respectively. **Response:** Change made. On page 39 of the redlined VRF/VSL Justification, in the discussion of FERC VSL G1, change "...being based the..." to "...being based on the..."On page 2 of the redlined Mapping Document, in the Comments column, change "...a review upon a Bulk Electric System (BES) interrupting device operation..." to something like "...a review upon a Bulk Electric System (BES) interrupting device operation initiated by a Protection System and not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities..." Explicitly reviewing and (more to the point) documenting each BES interrupting device operation is overly burdensome, as this would include control operations, including those associated with switching, as well as operations caused during on-site activities. **Response:** The comment was intended to provide a discussion of how the requirement in PRC-004-3 is better than the requirement in PRC-003. The text does not convey all the details of PRC-004-3 which include the identification of conditions which are not Misoperations. The drafting team does not believe the addition of the clarification requested is needed to justify for the replacement of PRC-003 requirement R1. No change made. On pages 4 and 19 of the redlined Mapping Document, in the Comments column, change "...a reverse power relay operated to remove a generating unit from service..." to something like "...a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection..." Whether it is for a protective or control function, the reverse power relay will still remove the generating unit from service; the distinction is why the generating unit is being removed from service. **Response:** The language has been changed. On page 5 of the redlined Mapping Document, in the Comments column, change "...underfrequency load shedding (UFLS)..." to "...underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements..." The Applicability does not include UFLS that trips non-BES Elements (e.g., medium voltage distribution feeders).

	Response: The language has been changed. On page 21 of the redlined Mapping Document, in the Comments column, change "...until is..." to "...until it..." **Response:** The language has been changed.
PPL NERC Registered Affiliates	The expression, "the Misoperation," in R5 should be changed to, "a determined Misoperation," in recognition of the fact that some events can be classified only after full investigation, as described above. **Response:** Requirement R5 does not come into the process until the owner of the Protection System component(s) has identified the cause of a Misoperation. Requirement R5 is implicitly pursuant to finding the cause in R1, R3, or R4 as illustrated by: "…first identifying a cause of the Misoperation." No change made.
Hydro-Québec Production	The purpose of the Standard shall be limited only to "Identify and correct the causes of Protection System Misoperations affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC. **Response:** Using the "affecting the reliability of the BES" has the effect of expanding applicability because all BES Elements are already included. Adding "affecting" would include other Protection Systems. The drafting team contends that the proposed Purpose statement does address Protection Systems that affect the BES. No change made.
Tennessee Valley Authority	The Severity Level wording (re CAP development) is too stringent and very confusing. Adding roughly 5 days (from the timeframe stated in the previous draft) is negligible. The current requirement allows 12 months for CAP development, and changing this to 120 days will not, in some cases, give a utility adequate time to investigate/determine actions going forth. **Response:** CAP development (60 days) is performed after the investigation is complete. It is separate from the "120 day" time period for identifying a Misoperation.

	A CAP is "a list of actions and an associated timetable for implementation to remedy a specific problem." Since CAP's address specific problems, the investigation into what went wrong needs to be completed before a CAP is developed. Per requirement R5, the 60 day CAP development time frame begins once the specific problem that caused a Misoperation is identified. The CAP implementation period is determined by the GO, TO, or DP developing the CAP. No change made.
Public Service Enterprise Group	There is no requirement in the standard for the cause of a Misoperation to be determined by the appropriate Protection System owner. Neither R1 nor R3 obligates the owner to attempt to determine the cause of a Misoperation. We note that R4 presumes the owner could not "determine the cause(s) of a Misoperation in accordance with R1 and R3" when those requirements contain no such obligation. R5 and R6 apply to an owner that has determined the cause(s) of a Misoperation. Therefore, we recommend that R1 and R3 be modified as follows with the following additional capitalized language:".... shall identify whether its Protection System component(s) caused a Misoperation OR NOT, AND IF SUCH A MISOPERATION OCCURRED, SHALL DETERMINE, IF POSSIBLE, THE CAUSE(S) OF SUCH MISOPERATION. **Response:** Requirements R1 and R3 are for determining whether a Misoperation occurred or not. Requirement R4 is for determining the cause(s), if not determined while performing Requirements R1 or R3. Requirement R4 has been clarified. Change made. "As R1 and R2 are written, one could interpret the language as requiring ALL interruption device operations be evaluated. However, this is not the intent based upon the draft RSAW that's posted. It states that the evidence required in R1 is "A list of BES interrupting device operations within audit period meeting the criteria of Requirement R1 Parts 1.1 through 1.3." Therefore, we recommend that R1 and R2 be changed so that it is clear that the only interruption device operations that need to be examined are those that are the unexpected. Expected operations for, as an example, switching would be eliminated from any requirement to review the interrupting device operation. This would greatly simplify the data required to demonstrate compliance. We offer the following additional capitalized language in R1 and R2:"Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated UNEXPECTEDLY shall,...."

	Response: Only BES interrupting device operations caused by a Protection System, a Composite Protection System, or by a manual intervention in response to a Protection System failure need to be investigated. This is stated in Requirements R1.1 and R2.1. No change made.
Exelon	This draft is a significant improvement over the last draft, specifically because of the addition of the “Composite Protection System”. We also endorse the use of the rationale boxes within the standard; they lend additional clarity to the requirements of the standard. However, consistent with our comments above, the standard is too prescriptive. For example, there is far too much emphasis on documenting dates. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. Additionally, most of the VSL’s should be eliminated and labeled “N/A”, e.g., on R3, does 30 calendar days really matter? Lower VSL should be up to 60 days late, Moderate is N/A, High is N/A, Severe is more than 60 days late which equals failed to identify. **Response:** The drafting team followed NERC Violation Severity Level Guidelines for VSL escalation. No change made. ComEd also disagrees with the VSL tables because they disproportionately propose to punish a larger utility with more operations (and misoperations). **Response:** The drafting team contends that the VSLs follow the NERC Violation Severity Level Guidelines and do not disproportionately burden a larger utility. The VSLs only apply when an entity fails to comply with the Requirements of the standard. A Misoperation is not a violation of the standard. No change made. There also needs to be a distinction between analyzing automatic operations for misoperations but failing to identify a misoperation in, as an example, 1 out of 100 operations verses taking no effort to identify any misoperations. For these reasons we think the current revision to PRC-004-3 is overly prescriptive and complicated. **Response:** The drafting team contends that each operation of a BES interrupting device according to the requirements is a discrete instance; therefore, a violation would be assessed for not reviewing the

	operation for Misoperation. For example, an entity that failed to review 100 operations would have 100 violations whereas an entity that failed to review one operation would have only one violation. No change made. Suggest that the SDT should evaluate simplifying the Standard to the basic purpose which is to "identify and correct the causes of Misoperation of Protection Systems for BES elements" without introducing hard timelines, overly prescriptive communication requirements, and documentation of the level of corrective actions performed. **Response:** The drafting team contends that the proposed version provides additional clarity over the current version. For example, the proposed version identifies who does what under what circumstances. No change made. Guidelines and Technical Basis: (1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. Can the drafting team provide an example for generator protection similar to the one provided for the transmission line protection? **Response:** The drafting team added Example 1d to address this concern. Change made. (2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation. If the generator is tripped by another relay say out of step, should it still be called misoperations? **Response:** Based on the information provided, the drafting team believes that the out-of-step relay is part of the generator's Composite Protection System; therefore, as described in this example the operation is not a Misoperation.
Virginia State Corporation Commisison	Under R5, the owner of a Protection System component that causes a Misoperation shall either develop a CAP or "Explain in a declaration why corrective actions are beyond the entity's control or would not

	improve BES reliability....." I wonder whether the Requirement should identify to whom and by what manner any such "declaration" should be made? **Response:** A declaration is documentation retained by the entity to explain why development of a CAP would not improve reliability and that no further corrective actions will be taken. An entity would have a declaration available to provide to its Regional Entity during a compliance monitoring activity. No change made.
ReliabilityFirst Protection Subcommittee	We believe that the rationale boxes within the standard should be retained to lend additional clarity to the requirements of the standard. **Response:** When this standard has received ballot approval, the rationale boxes are retained and will be moved to the Application Guidelines Section of the Standard. No change made.
Wisconsin Electric Power Company	We strongly believe that the drafting teams need to understand how the standards they are developing will interact with other NERC standards and documents. There may be unintended consequences when the relationships between two standards or other NERC documents are not foreseen. Regrettably, the SDT for the new BES Definition failed to take into account the substantial impact of its product on the various standards that would be applied to the new BES elements. Therefore it is critical for the PRC-004-3 SDT to take a step back and anticipate the effect of the new BES definition on this standard. The case in point is the addition of dispersed generators to the BES. We remain very concerned with the effort that will be required to comply with this standard in light of the new BES facilities that are included in the new BES definition, especially dispersed generation. It is wind that especially troubles us. We have about 200 wind turbine generators in our fleet, all less than 2 MW in size. Wind makes up less than 5 % of our generation capacity. Yet, in terms of the sheer number of generators, the number of wind units is roughly 5 times the number of other larger generators in our fleet. Of these 200 wind generators, 90% will soon become BES generators due to being aggregated in facilities above 75 MVA. It is the outsized impact of these wind turbines that will have a huge effect when we are required to analyze in depth each protection system operation of these wind generators in order to comply with PRC-004-3. This effort will be enormous, and yet the reliability benefit is negligible. The valuable technical resources available at my company, and at

	many other companies with even larger amounts of dispersed generators, are not best utilized by applying this standard at the level of individual wind generators, and other similar small dispersed generators. To allow entities to focus limited technical resources on efforts that truly enhance reliability, the SDT should revise the Applicability to specifically exclude small dispersed generators, and only apply it where the aggregated generation exceeds 75 MVA, that is, to the collector bus and transformer (with the high-side winding operated at or above 100 kv) used to connect to the transmission system. We believe the extra time it takes to think this through will be worthwhile to the industry, and may prevent inadvertent outcomes that may not serve the overall reliability of the bulk power system. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
Seminole Electric Cooperative, Inc.	WECC Extended Implementation Period - The Standard as proposed allows entities in the WECC Region an additional 12-months to comply with the Requirements of PRC-004-3. Seminole requests that entities in all other NERC Regions have the same amount of time to comply. Correlating every Region's effective date to that of WECC would be just, reasonable, and less preferential. **Response:** After further review and discussion with WECC following the latest changes to the standard, the proposed standard and the existing regional standard do not conflict. Therefore, different implementation timeframes are no longer necessary. However, the language used in the implementation plan is the stock language NERC uses for effective dates of Reliability Standards. In the prior version of the implementation, the effective dates were specified separately for WECC to provide time to eliminate language conflicts between the proposed standard and the regional standard. Since no conflict exists, there will be a single effective date for the standard. Change made.

	Evidence Retention - Bullet 2 under section C.1.2. of the Standard deals with evidence retention. Bullet 2 specifically requires retention of evidence 12 months from the date of "completion of each CAP, evaluation, and declaration." It does not appear that Requirement R5 covers the completion of the CAP; it appears that specific requirement is covered in Requirement R6 and bullet #3 of the evidence retention section. Seminole reasons that the drafting team meant Bullet 2 to state that the retention period is from the date of completion of the "development" of a CAP, not the completion of remedies stated in a CAP. In addition, there are three possible dates for completion of a CAP, evaluation, and declaration. Seminole requests that the drafting team clarify which date, and time period, specific evidence is required. **Response:** Bullet 2 under Section C.1.2 has been redrafted to indicate the data retained should support the development of the CAP in Requirement R5. Change made. When a CAP is developed in accordance with Requirement R5 there will be two dates. One for the completion of the development of the CAP and a second for the completion of an evaluation of the applicability of the CAP at other locations. In the case where a declaration is made that no further corrective actions will be taken, the date will be when the declaration was made. Measure M5 gives examples of acceptable evidence. When a CAP is completed in accordance with Requirement R6 the dates of the completion of actions within the CAP as well as any modifications to the CAP should be retained. Measure M6 gives examples of acceptable evidence.

END OF REPORT

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. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.
6. Draft 4 of PRC-004-3 was posted for a 45-day additional comment period from January 17 – March 11, 2014 and an additional ballot in the last ten days of the comment period from February 2 – March 11, 2014 under the new Standards Process Manual (Effective: June 26, 2013).

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft 5 of PRC-004-3 – Protection System Misoperation Identification and Correction for a 45-day additional comment period and additional ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Ballot	May 2014
10-day Final Ballot	July 2014
BOT Approval	August 2014

Effective Dates

The standard, the revised definition of “Misoperation” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of

"Misoperation" and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	

2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	TBD	Adopted by Board of Trustees	Revision under Project 2010-05.1

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 *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary") are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NERC Glossary.

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided to a remote Protection System is included.

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-3

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

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 for BES Elements, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and

[1] For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a “fill-in-the-blank” standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information (“data request”). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. Effective Dates:

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific others that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which that backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that when Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc. In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hard copy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following development of each CAP, development of each evaluation, and development of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

None.

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[2] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[3]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[4]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a fault or non-fault condition.

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[2] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf
[3] http://www.nerc.com/files/2011_RARPR_FINAL.pdf
[4] "Transmission Protective Relay System Performance Measuring Methodology," Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided to a remote Protection System is included.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

> **Misoperation –** *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*
>
> 1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
> 2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
> 3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
> 4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
> 5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*
> 6. ***Unnecessary Trip – Other Than Fault*** – *An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

Failure to automatically reclose after a fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.

A breaker failure operation does not, in itself, constitute a Misoperation.

A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a “Failure to Trip – During Fault” Misoperation as long as another component such as a generator differential relay operated.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.
>
> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the fault is cleared.

> **Example 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line fault is a Misoperation. The current differential element of a multiple function relay failed to operate for a line fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line fault is a Misoperation. The fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-fault conditions include but are not limited to, power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation.

The "on-site" activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal.

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements, are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization. The operation trips only the capacitor bank breaker that was closed to energize the bank. Since closing the breaker put the capacitor bank into service, this is a Misoperation.

> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush following a maintenance outage. Only the high-side breaker opens since the low-side breaker had not yet been closed. Since closing the breaker put the transformer bank into service, this is a Misoperation.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement R1

This requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case, BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, Requirement R2, Part 2.2 requires the entity that had the BES interrupting device operation to notify the other owner(s) to review its portion of Composite Protection System for Misoperation.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner’s differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under requirement R1. This is consistent with NERC SPCS guidance.

Repeated Misoperations which occur during the same 24 hour period do not need a separate identification under requirement R1. This is consistent with NERC PSMTF guidance.

When Elements are isolated from the BES and undergoing maintenance, they are not subject to the standard, provided they do not result in the operation of any interrupting devices that are part of the BES.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.
>
> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, was required to notify the Generator Owner of the operation. The Generator Owner investigated to determine if its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the latter half of the 120 calendar days allotted to the BES interrupting device owner.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[5]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

[5] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf, Figure 15: NERC Wide Misoperations by Cause Code, pg. 22 of 40.

Example R4b: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

Example R4c: A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must create the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation; in these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAPs to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The time periods within Requirement R1, R3 and R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of the CAPs in examples R5a through R5d, please see examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

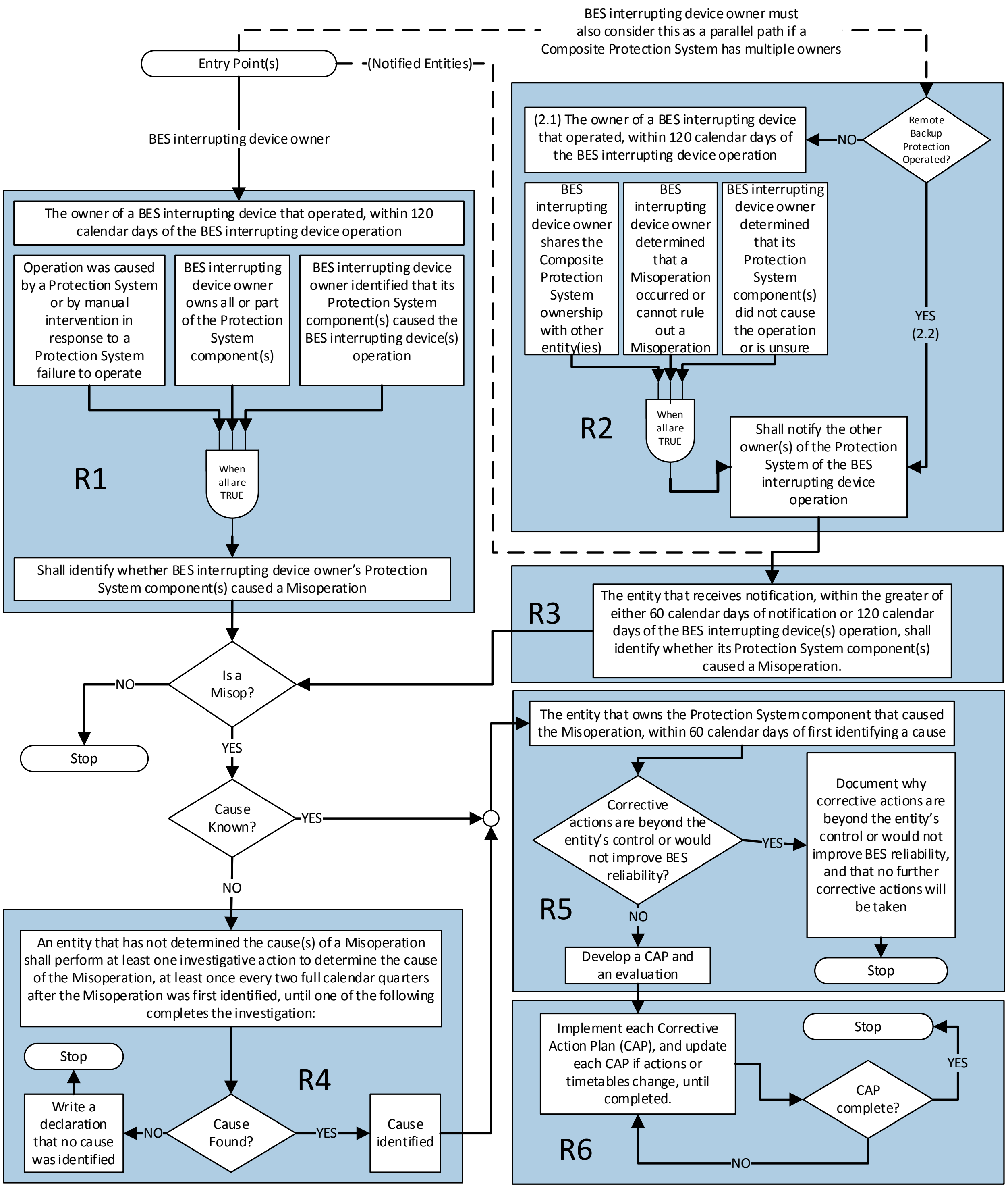
Example R6d: Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between requirements:



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. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.
6. Draft 4 of PRC-004-3 was posted for a 45-day additional comment period from January 17 – March 11, 2014 and an additional ballot in the last ten days of the comment period from February 2 – March 11, 2014 under the new Standards Process Manual (Effective: June 26, 2013).

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft ~~4~~5 of PRC-004-3 – Protection System Misoperation Identification and Correction for a 45-day additional comment period and additional ballot in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Ballot	~~January~~May 2014
10-day Final Ballot	~~March~~July 2014
BOT Approval	~~May~~August 2014

Effective Dates

~~Except in the Western Interconnection, the~~ The standard, the revised definition of "Misoperation" and ~~definitions~~the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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. ~~Except in the Western Interconnection, where~~Where approval by an applicable governmental authority is not required, the standard, the revised definition of "Misoperation" and ~~definitions~~the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~In the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months 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. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's	

		Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
~~1~~3	TBD	~~Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)~~Adopted by Board of Trustees	~~New~~Revision under Project 2010-05.1

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 *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary") are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the ~~glossary~~NERC Glossary.

Composite Protection System:

The total complement of ~~the~~ Protection System(s) that function collectively to protect an Element~~, such as any primary, secondary, local backup, and communication-assisted relay systems.~~. Backup protection provided ~~by~~to a remote Protection System is ~~excluded~~included.

Misoperation:

The failure of a Composite Protection System to operate as intended~~.~~ for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition ~~for which it is designed. Delayed clearing~~if the duration of ~~a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition ~~for which it is designed~~, such as a power swing, undervoltage, overexcitation, or loss of excitation~~. Delayed clearing~~, if the duration of ~~a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition ~~for which it is not designed. A~~. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

When this standard has received ballot approval, the ~~text~~rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
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 for BES Elements~~. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.[1]~~, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[2]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are ~~not included~~excluded in this standard because they are planned to be handled in the second phase of this project.

~~[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.~~

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

5. Background:

A key ~~element~~factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needs more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical yet explainable condition is a Misoperation.

The SAR for this project also includes clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

6. Effective Dates: ~~See Implementation Plan~~

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation ~~when~~under the following circumstances: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

~~**M1.**~~ **M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to~~,~~ the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This requirement ensures that entities review those Protection System operations meeting the ~~criteria~~circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner ~~has~~is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, ~~notify the other owner(s) of the Protection System of the operation when:~~provide notification as described in 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

~~2~~**2.1** For a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other ~~entity~~owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1~~, 2.2,~~ and 2.~~3~~2 may include, but is not limited to~~,~~ the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: ~~This requirement~~Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System~~ when the criteria in all three Parts (2.1, 2.2, and 2.3) are met~~. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific others that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which that backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that ~~the three conditions~~when Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, ~~shall~~ identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to~~,~~ the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to~~,~~ the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations~~,~~; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to~~,~~ the following dated documentation (electronic or hardcopy format): ~~a dated~~ CAP and evaluation, or ~~a dated~~ declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc. In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the ~~close of the Misoperation in lieu~~absence of a CAP~~ and for future reference~~.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to~~,~~ the following dated documentation (electronic or hard copy format): ~~dated~~ records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: ~~The~~Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP tivities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for 12 calendar months.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following ~~completion~~development of each CAP, development of each evaluation, and development of each declaration.
- The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

None.

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the 2011 Risk Assessment of Reliability Performance[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[5]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a ~~Fault~~fault or non-~~Fault~~fault condition.

[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf
[4] http://www.nerc.com/files/2011_RARPR_FINAL.pdf
[5] "Transmission Protective Relay System Performance Measuring Methodology," Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society, 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of ~~the~~ Protection System(s) that function collectively to protect ~~a~~an Element~~, such as any primary, secondary, local backup, and communication-assisted relay systems.~~. Backup protection provided ~~by~~to a remote Protection System is ~~excluded~~included.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the ~~entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally, the definition accounts for those Protection Systems with multiple levels of protection (e.g., redundant systems), such that if one component fails, but the overall intended performance of the composite protection is met – it would not be identified as a Misoperation under the definition~~overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
3. ***Slow Trip – During Fault*** – *A Composite Protection System operation that is slower than required for a Fault condition ~~for which it is designed. Delayed clearing~~if the duration of ~~a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one* other *Element's* Composite Protection *System.*
4. ***Slow Trip – Other Than Fault*** – *A Composite Protection System operation that is slower than required for a non-Fault condition ~~for which it is designed~~, such as a power swing, undervoltage, overexcitation, or loss of excitation~~. Delayed clearing~~, if the duration of ~~a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one* other *Element's* Composite Protection *System.*
5. ***Unnecessary Trip – During Fault*** – *An unnecessary Composite Protection System operation for a Fault condition on another Element.*

6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition ~~for which it is not designed. A~~. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

Failure to automatically reclose after a ~~Fault~~fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.

A breaker failure operation does not, in itself, constitute a Misoperation.

A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended. The definition includes six categories which provide further differentiation ~~and examples~~ of what ~~is~~constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the ~~Fault~~fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer ~~Fault~~fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer ~~Fault~~fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated ~~to clear the Fault~~.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.
>
> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as ~~another component of~~ the generator's Composite Protection System operated as intended ~~(e.g.,~~ isolating the generator~~).~~ from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the ~~Fault~~fault is cleared.

> **Example 3:** A failure of a line's Composite Protection System to operate as quickly as intended for a line ~~Fault is a Misoperation~~fault is a Misoperation. The current differential element of a multiple function relay failed to operate for a line fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System ~~operated slower than the objective of the owner(s).~~. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System ~~operated slower than the objective of the owner(s).~~. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation. ~~This category of Misoperation could result in equipment damage.~~

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the ~~Fault~~fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the ~~Faulted~~faulted Element to clear the ~~Fault~~fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line ~~Fault~~fault is a Misoperation. The ~~Fault~~fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-~~Fault~~fault conditions include but are not limited to, power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

Example 6c: An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Example 6d: Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-~~Fault~~fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example ~~6d~~6e: A BES interrupting device operation that occurs at the remote end of a line during a non-~~Fault~~fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation.

The "on-site" activities at one location that initiates a trip to another location are included in this exemption; however, once the maintenance, testing, inspection, construction, or commissioning is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations which occur with the protected Element out of service, that do not trip any in-service Elements, are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for ~~Faults~~faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer ~~Fault~~fault operated as intended and would not be a Misoperation.

~~The above~~Below are examples ~~only, and do not constitute an all-inclusive list~~ of conditions that would ~~not~~ be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization. The operation trips only the capacitor bank breaker that was closed to energize the bank. Since closing the breaker put the capacitor bank into service, this is a Misoperation.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush following a maintenance outage. Only the high-side breaker opens since the low-side breaker had not yet been closed. Since closing the breaker put the transformer bank into service, this is a Misoperation.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.
>
> ~~In the example above, the~~

The standard is not applicable~~; however~~ to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay ~~as a part of the generator Protection System~~ when ~~intended to provide generator anti-~~it operates for conditions not associated with the controlled shutdown sequence, such as a motoring ~~protection. For example, reverse power relays are typically installed as~~condition caused by a trip of the ~~primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit~~prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, ~~says~~reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement R1

This requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified ~~that~~ its Protection System component(s) as causing the BES interrupting device operation.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case, BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, Requirement R2, Part 2.2 requires the entity that had the BES interrupting device operation to notify the other owner(s) to review its portion of Composite Protection System for Misoperation.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under requirement R1. This is consistent with NERC SPCS guidance.

Repeated Misoperations which occur during the same 24 hour period do not need a separate identification under requirement R1. This is consistent with NERC PSMTF guidance.

When Elements are isolated from the BES and undergoing maintenance, they are not subject to the standard, provided they do not result in the operation of any interrupting devices that are part of the BES.

Requirement R2

~~For~~ Requirement R2 ~~(i.e.,~~ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership~~),~~, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a

Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking ~~or~~ (DCB) relaying on 03/03/2014 at 15:43 UTC during an external fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, was required to notify the Generator Owner of the operation. The Generator Owner investigated to determine if its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the

Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the latter half of the 120 calendar days allotted to the BES interrupting device owner.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, ~~the entity~~ is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, ~~or~~ requesting ~~a necessary~~an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[6]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan ~~or~~ (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must create the CAP or make a declaration why additional actions are beyond the entity's

[6] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf, Figure 15: NERC Wide Misoperations by Cause Code, pg. 22 of 40.

control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation; in these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAPs to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The time periods within Requirement R1, R3 and ~~Requirement~~ R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity’s other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP ~~must include~~and an evaluation of other Protection Systems including other locations ~~to~~must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of the CAPs in examples R5a through R5d, please see examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5b: Actions: Remove the relay from service. Replace capacitor~~.~~ in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

Example R5c: Actions: Remove the relay from service. Replace capacitor~~.~~ in the relay. Test the relay. Return to service or replace by 07/01/2014.

Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.

A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

Example R5d: Actions: Provide the manufacturer ~~Fault~~fault records. Install new firmware pending manufacturer results by 10/01/2014.

Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity’s control or would not improve BES reliability and that no further corrective actions will be taken.

Example R5e: The cause of the Misoperation was due to a non-registered entity communications provider problem.

Example R5f: The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity’s transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity’s control.

The following ~~in an example~~are examples of ~~a declaration~~declarations made why corrective actions would not improve BES reliability.

Example R5g: The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase fault. The protection scheme utilized for both protection groups is a ~~POTT.~~permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. ~~The~~A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

Example R6b: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. ~~The~~A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.

CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay~~;~~ and preemptive actions for similar installations (See also, Example R5c).

Example R6c: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. ~~The~~A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due resource rescheduling from a scheduled 02/01/15 completion to ~~03~~04/01/2015~~. Following the timetable change, capacitor~~ completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.

CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem~~;~~ and preemptive actions for similar installations. (See also, Example R5d).

Example R6d: Actions: ~~Fault~~fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.

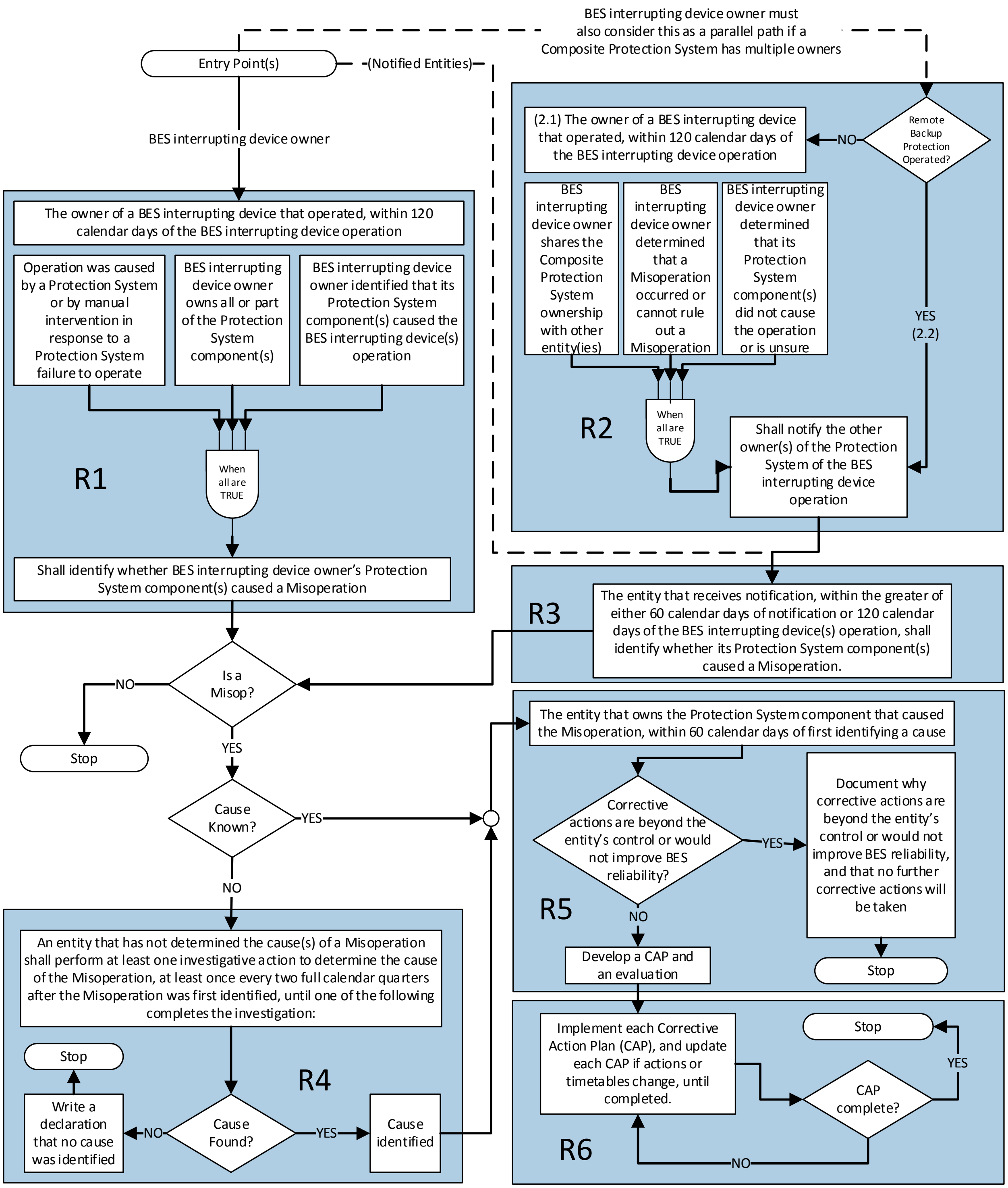
Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.

CAP completed on 11/10/2014.

The CAP is complete when all of the ~~documented~~ actions ~~to resolve~~identified within the ~~specific problem (i.e., Misoperation) are~~CAP have been completed~~ which may include those actions~~

~~resulting from the entity's evaluation of other locations, if not addressed through a separate CAP.~~.

Process Flow Chart: Below is a graphical representation ~~of the expected process created by the standard, including~~demonstrating the relationships between requirements:



NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction
- Definitions of "Composite Protection System" and "Misoperation"

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided to a remote Protection System is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

The standard, the revised definition of "Misoperation" and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of "Misoperation" and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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

The existing standards, PRC-003-1 and PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-3.

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction
- Definitions of "Composite Protection System" and "Misoperation"

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of ~~the~~ Protection System(s) that function collectively to protect an Element~~, such as any primary, secondary, local backup, and communication-assisted relay systems.~~. Backup protection provided ~~by~~to a remote Protection System is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended~~.~~ for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition ~~for which it is designed, such as a power swing, undervoltage,~~

~~overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as~~if the ~~performance of~~duration of its operating time resulted in the operation of at least one other Element's Composite Protection System~~ is correct~~.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition ~~for which it is designed. Delayed clearing~~if the duration of ~~a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one other Element's Composite Protection System.

4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition~~ for which it is designed~~, such as a power swing, undervoltage, overexcitation, or loss of excitation~~. Delayed clearing~~ if the duration of ~~a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or~~its operating time resulted in the operation of ~~any~~at least one other Element's Composite Protection System.

5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.

6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition~~ for which it is not designed. A~~. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. ~~The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.~~The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

~~Except in the Western Interconnection, the~~ The standard, the revised definition of "Misoperation" and ~~definitions~~the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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. ~~Except in the Western Interconnection, where~~Where approval by an applicable governmental authority is not required, the standard, the revised definition of "Misoperation" and ~~definitions~~the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

~~In the Western Interconnection, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months 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. In the Western Interconnection, where approval by an applicable governmental authority is not required, the standard and definitions shall become effective on the first day of the first calendar quarter that is twenty-four months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~Implementation Plan for PRC-004-3, All Requirements~~

~~Each Transmission Owner, Generator Owner, and Distribution Provider applicable to this standard shall be 100% compliant upon the effective date of the standard.~~

~~The extended implementation for the Western Interconnection is provided to allow an opportunity to make the necessary changes to the PRC-004-WECC-1 Regional Reliability Standard. An overlap in performance between the regional and proposed continent-wide standard was identified during the development of the proposed PRC-004-3 Reliability Standard.~~

~~**Implementation Plan for definitions**~~

~~The revised definition of Misoperation and the new definition of Composite Protection System shall be implemented concurrently with the standard upon the effective dates noted above. Note that the Western Interconnection has an extended implementation.~~

Retirement of Existing Standards

~~Except in the Western Interconnection, the~~The existing standards, PRC-003-1 and PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the ~~effective date~~Effective Date of PRC-004-3. ~~In the Western Interconnection, the existing standards PRC-003-1 and PRC-004-2.1a shall be retired at midnight of the day immediately prior to the effective date of PRC-004-3 for the Western Interconnection.~~

Unofficial Comment Form

Project 2010-05.1 Protection System Misoperations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the PRC-004-3 Standard **by 8:00 p.m. ET, June 30, 2014**.

If you have questions please contact Scott Barfield-McGinnis at scott.barfield@nerc.net or by telephone at 404-446-9689.

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

Background Information

The fourth draft of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard was posted for a 45-day formal comment period from January 17 – March 11, 2014 with an additional ballot in the last ten days of the comment period according to the new Standards Process Manual, June 26, 2013. Stakeholders from approximately 99 companies representing nine of ten industry segments provided comment. The Protection System Misoperation Standard Drafting Team (PSMSDT or SDT) has responded to all commenters and developed a fifth draft of the standard based on stakeholder comment. Changes to the standard include, but are not limited to following areas.

Summary of Changes

The PSMSDT made two substantive revisions to the previous draft 4 following the additional 45-day formal comment period of the standard and additional ballot which received 62.63% stakeholder approval. The following narrative is a summary of the two substantive revisions and other minor revisions made to the proposed draft 5 of the standard.

Definitions

The definition of "Composite Protection System" was revised for clarity. The first substantive revision is the definition of "Misoperation" concerning the two categories of "Slow Trip – During Fault." The revision removes the "a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability" and uses the more clear "…if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System." The last category of "Unnecessary Trip – Other Than Fault" was revised slightly to clarify that a Protection System operation caused by on-site personnel is not a Misoperation and the SDT made other corresponding revisions to insert word "Composite" before "Protection System" for consistency with the proposed definition of "Composite Protection System."

Purpose Statement

No revisions.

Facilities
An exclusion for Remedial Action Schemes (RAS) and Special Protection System (SPS) has been provided to increase clarity that these Protection Systems are not applicable to the standard.

Effective Dates
The extended implementation provision of 24 calendar months previously provided to entities in the Western Electric Coordinating Council (WECC) Region was eliminated. The provision was originally proposed due to a perceived conflict that is no longer valid. The effective date language was inserted into Section 6 of the standard for completeness.

Requirement R1
The SDT made a non-substantive revision to more clearly describe that the BES interrupting device operation that meets the three sub-parts (i.e., 1.1, 1.2, and 1.3) must all be true to have a Protection System operation that is reviewable for Misoperation.

Requirement R2
The requirement is the second substantive revision to address a gap in performance identified through continued review during the formal comment period. The previous draft did not have a provision for the responsible entity to initiate a reliability activity under the standard in the case of a Protection System failure to operate a BES interrupting device which is what initiates the activity to review for Misoperation.

The SDT determined that a failed Protection System would cause backup protection to operate other BES interrupting devices; therefore, it is practical to have the responsible entity that provided backup protection to notify the other entity of the potential failure. It is the notification that eliminates the gap and causes the other entity to review the Protection System for Misoperation under the next Requirement, R3.

Requirement R3
Minor word change.

Requirement R4
Minor clarity revision by adding “for a Misoperation” to more clearly reference the Misoperation identified in either Requirement R1 or R3.

Requirement R5
No change.

Requirement R6
No change.

Measures M1-M6
Each of the six Measures were updated to provide the entity that is required to demonstrate compliance, what is demonstrated, and the reference to the corresponding Requirement. Revisions were based on stakeholder comment and to be consistent with drafting team guidance for developing Measures.

Compliance
The SDT clarified for Requirement R5 that evidence retention relates to the "development" of the Corrective Action Plan (CAP), each evaluation, and each declaration.

VRFs and VSLs
The drafting team made a couple of minor typographical corrections identified by stakeholders.

Application Guidelines
The SDT made a significant number of additions and clarifications to address stakeholder comment. Most notably in the section discussing the definition of Composite Protection System.

Questions

Entities are encouraged to answer all questions and provide comment as requested in the questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained in this system.

1. Based on stakeholder input, the drafting team revised the proposed definition of "**Misoperation**." Concerning the two categories of "Slow Trip." The drafting team also clarified the proposed definition of "Composite Protection System." Do you agree the revisions provided clarity? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

2. Based on stakeholder input, the drafting team revised Requirement R2 to clarify responsibilities when local protection is responsible for the interrupting device operation and when backup protection is responsible. This also addresses the notifications that must occur to eliminate a gap in the previous draft. The gap was a condition where an entity's BES interrupting device did not operate because of a failed Protection System; therefore, would not have been applicable to the standard. Do you agree that the gap has been eliminated with the change to Requirement R2? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

3. The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

4. If you have any other comments on this Standard that were not provided in response to the previous questions, please provide them here:

   Comments:

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the standard drafting team is recommending revisions to the standard, those changes are identified in the “Translation to PRC-004-3 or Other Action” column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered entity functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based standard (RBS) construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also directs focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners that share a Misoperation identification responsibility of the Composite Protection System when it determines (or is unsure) its Protection System component(s) did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		continue its investigative work to determine the cause(s) of an identified Misoperation, if not determined in R1 or R3, until the cause(s) is determined or the entity declares that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**4.2.** Facilities: **4.2.1** Protection Systems for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded and will be addressed in phase two of this project and have been excluded in the Applicability.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances:	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.	ensuring that other owners had a responsibility to be involved in the review and analysis.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2.	Requirement R2 asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and a Misoperation occurred (or cannot be

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1 When a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System	ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device owner in performing Requirement R1 determines that it's Protection System operated as backup for another BES interrupting device which has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 for the other owner.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause(s) of a Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of applicable entities. As such, Regional reporting will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. Metrics will be shared with each Region. The removal of the data collection from the standard does not result in a reduction of reliability.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may document this as well and not make a change. In cases where the entity, in its judgment, determines that a CAP is not practical for improving BES reliability, the entity must explain in a declaration its conclusions why no further action will be taken.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection Systems for BES Elements without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard, revised definition of “Misoperation,” and new definition of “Composite Protection System” provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity’s (formerly Regional Reliability Organization or RRO) approval. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator	None.	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Owners within 30 calendar days of approval of those procedures.		

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS).	The same applicable entities will transition to the new PRC-004-3 standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service) are not applicable. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	addressed in phase two of this project and have been excluded in the Applicability.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and The BES interrupting device owner identified that its Protection System component(s)	The currently approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3). The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation was not caused (or is undetermined) by the

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	caused the BES interrupting device(s) operation. **R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and	BES interrupting device owner and a Misoperation occurred (or cannot be ruled out) in accordance with criteria 2.1 through 2.3. Requirement R3 provides the necessary performance for the notified Protection System owner to review its component(s) for Misoperation. Last, Requirement R4 requires the applicable entity to conduct investigative actions until it determines the cause(s) or declares that it has been unable to determine the cause(s). Requirement R5 addresses the "develop" a Corrective Action Plan (CAP)" portion, and Requirement R6 addresses the "implement" portion of the CAP.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	System owner(s) for which that backup protection was provided. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation:	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	• The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	None.	Since the NERC Rules of Procedure, Section 1600 Request for Data or Information will replace the reporting obligations, NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the standard drafting team is recommending revisions to the standard, those changes are identified in the "~~Proposed Replacement~~Translation to PRC-004-3 or Other Action" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered entity functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based standard (RBS) construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also ~~direct~~directs focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners that share a Misoperation identification responsibility of the Composite Protection System when it determines (or is unsure) its Protection System ~~components~~component(s) did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		R1. Requirement R4 directs the applicable entity to continue its investigative work to determine the cause(s) of an identified Misoperation, if not determined in R1 or R3, until the cause(s) is determined or the entity ~~concludes~~declares that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to	**4.2.** Facilities: **4.2.1** Protection Systems for BES Elements~~.~~, with the following exclusions:	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
their potential impact on BES reliability).	**4.2.1.1** Non-protective functions that are embedded within a Protection System ~~are excluded.~~. **4.2.1.2** Protective functions intended to operate as a control function during switching ~~are excluded.~~. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for BES Elements. Additional language is provided for clarity that non-protective functions ~~are not applicable~~ and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service~~). The~~ as opposed to providing anti-motoring protection) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded and will be addressed in phase two of this project and have been excluded in the Applicability.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation ~~when~~under the following circumstances: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.	through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for ensuring that other owners had a responsibility to be involved in the review and analysis.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R2.** ~~Each~~ Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, ~~notify the other owner(s) of the Protection System of the operation when:~~provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection	Requirement R2 ~~now~~ asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and a Misoperation occurred (or cannot be ruled out) in accordance with ~~criteria~~Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** ~~2.3~~ The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device owner in performing Requirement R1 determines that it's Protection System

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.	operated as backup for another BES interrupting device which has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 for the other owner.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, ~~shall~~ identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review ~~with~~within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 days) to review an operation, the receiving entity will always have

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		a minimum and reasonable time (60 days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause(s) of a Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when ~~a~~the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it ~~has taken reasonable action and~~ could not determine the cause.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of applicable entities. As such, Regional reporting will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. Metrics will be shared with each Region. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation:	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	• Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may document this as well~~.~~ and not make a change. In cases where the entity, in its judgment, determines that a CAP is not practical for improving BES reliability, the entity must explain in a declaration its conclusions why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection ~~System~~Systems for BES Elements without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard ~~and~~, revised definition of "Misoperation," and new definition of "Composite Protection System" provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity's (formerly Regional Reliability Organization or RRO) approval. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
and generation Protection System Misoperations.		update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.	None.	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements~~.~~, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded within a Protection System ~~are excluded.~~ . **4.2.1.2** Protective functions intended to operate as a control function during switching ~~are excluded.~~. **4.2.1.3** Special Protection Systems (SPS).	The same applicable entities will transition to the new PRC-004-3 standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions ~~are not applicable~~ and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service~~).~~) are not applicable. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	4.2.1.4 Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	Schemes (RAS) are addressed in phase two of this project~~.~~ and have been excluded in the Applicability.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation ~~when~~under the following circumstances: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and	The ~~already~~currently approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3). The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R2. The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. **R2.** ~~Each~~ Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, ~~notify the other owner(s) of the Protection System of the operation when:~~provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:	notified when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and a Misoperation occurred (or cannot be ruled out) in accordance with criteria 2.1 through 2.3. Requirement R3 provides the necessary performance for the notified Protection System owner to review its component(s) for Misoperation. Last, Requirement R4 requires the applicable entity to conduct investigative actions until ~~is~~it determines the cause(s) or declares that it has been unable to determine the cause(s). Requirement R5 addresses the "develop" a Corrective Action Plan (CAP)" portion, and Requirement R6 addresses the "implement" portion of the CAP.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, ~~shall~~ identify whether its Protection System component(s) caused a Misoperation. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its	None.	Since the NERC Rules of Procedure, Section 1600 Request for Data or Information ~~or Data~~ will replace the reporting obligations~~.~~, NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.		Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The following discussion addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-

004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. ” The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a “fill-in-the-blank” standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP’s applicability to the entity’s other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity’s control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives, thus a Requirement-to-Requirement comparison of VRFs is not possible. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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	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	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

	intent of the requirement.	intent of the requirement.	cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R1	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which both have a VRF of High. This Requirement R1, to “review” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. The VRF assignment also comports with the currently effective standards PRC-016-0.1 and PRC-022-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R1			
	Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

VRF and VSL Justifications – PRC-004-3, R1	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.

VRF and VSL Justifications – PRC-004-3, R2	
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This requirement and VRF of Medium is consistent with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"),MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), and IRO-015-1 – NAME, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2	
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R2			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R2	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R3			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R3	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, 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. An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which have a VRF of High. This Requirement R4, to perform at least one “investigative action” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

VRF and VSL Justifications – PRC-004-3, R4			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R5	
	An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future Misoperations”), PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”), FAC-003, R5 (“…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management”) all three of which have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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. An unresolved cause of a Misoperation could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R5			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR

VRF and VSL Justifications – PRC-004-3, R5			
			The responsible entity failed to develop an evaluation in accordance with Requirement R5.

NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R5	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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 Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which both have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

<table>
<tr><th colspan="4">VRF and VSL Justification – PRC-004-3, R6</th></tr>
<tr><td>FERC VRF G5 Discussion</td><td colspan="3">Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:

This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.</td></tr>
<tr><th colspan="4">Proposed VSL</th></tr>
<tr><th>Lower</th><th>Moderate</th><th>High</th><th>Severe</th></tr>
<tr><td>The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.</td><td>N/A</td><td>N/A</td><td>The responsible entity failed to implement a CAP in accordance with Requirement R6.</td></tr>
<tr><td colspan="4"></td></tr>
<tr><td>NERC VSL Guidelines</td><td colspan="3">Meets NERC’s VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.</td></tr>
<tr><td>FERC VSL G1</td><td colspan="3">Guideline 3- Consistency among Reliability Standards:

This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.</td></tr>
</table>

VRF and VSL Justification – PRC-004-3, R6	
Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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.
FERC VSL G3 Violation Severity Level 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 this Requirement.

VRF and VSL Justification – PRC-004-3, R6	
FERC VSL G4 Violation Severity Level 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.

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

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-004-3 — Protection System Misoperations.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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: [2]

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The following discussion addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. " The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1. First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another ~~entity~~owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete ~~requirement~~Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth ~~requirement~~Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, ~~the entity~~it must ~~make~~explain this in a declaration why ~~and that~~ no further corrective actions will be taken.

In the last ~~of the requirements,~~ Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the ~~requirements~~Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new ~~requirements~~Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives, thus a ~~requirement~~Requirement-to-~~requirement~~Requirement comparison of VRFs is not possible. In developing the new VRFs for the ~~requirements~~Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations~~,~~ (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation~~,~~ (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation~~,~~ (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance~~, R1~~ (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by ~~their~~an owner~~(s)~~ is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection ~~System~~Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard:

VRF and VSL Justifications – PRC-004-3, R1	
	~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This ~~proposed~~ Requirement R1, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. ~~The proposed~~A VRF of Medium ~~is~~does not inadvertently ~~lowering~~lower the ~~identified~~current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because ~~the proposed~~this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. The VRF assignment also comports with the currently effective standards PRC-016-0.1 and PRC-022-1.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R1	
	Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could in the planning time frame, 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. ~~The proposed~~This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The ~~proposed~~ VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: ~~The proposed~~This 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-004-3, R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	~~The proposed~~This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with ~~the requirement.~~this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify ~~a joint~~the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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. Unresolved Misoperations of ~~jointly~~Composite Protection Systems owned ~~equipment or operations~~by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report:

VRF and VSL Justifications – PRC-004-3, R2	
	This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System ~~components~~component(s) when it determines that (or is unsure whether)its ~~components~~component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the ~~jointly owned~~ Composite Protection System~~.~~ owned by others. This ensures that all ~~parties~~owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: ~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which ~~as~~both have a VRF of High. ~~The~~This requirement and VRF of Medium is consistent with Reliability Standards FAC-008-3 – Facility Ratings, R7 (“…shall provide Facility Ratings (for its solely and jointly owned Facilities~~…”) and~~ …”),MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 (“…shall provide appropriate equipment characteristics and system data~~…”) which both~~…”), and IRO-015-1 – NAME, R1.1 (“…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.”) which all have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R2	
	Other ~~protection systems~~Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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. Unresolved Misoperations of ~~jointly~~Composite Protection Systems owned ~~equipment or operations~~by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation:

VRF and VSL Justifications – PRC-004-3, R2			
	This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as ~~joint ownership~~Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: ~~The proposed~~This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	~~The proposed~~This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with ~~the requirement.~~this Requirement.

VRF and VSL Justifications – PRC-004-3, R2	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of ~~a joint~~another Composite Protection System owner to review its ~~components~~component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate ~~for Misoperation upon notification~~ could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection ~~System~~Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: ~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which ~~as~~both have a VRF of High. This ~~proposed~~ Requirement ~~R1,~~ R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. ~~The proposed~~A VRF of Medium ~~is~~does not inadvertently ~~lowering~~lower the ~~identified~~current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because ~~the proposed~~this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of ~~a joint~~another Composite Protection System owner to review its ~~components~~component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate ~~for Misoperation upon notification~~ could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R3			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. ~~The proposed~~A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. ~~The proposed~~This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: ~~The proposed~~This 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-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	~~The proposed~~This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with ~~the requirement.~~this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, 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. An Unidentified ~~causes~~cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: ~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which ~~as~~have a VRF of High. This~~ proposed~~ Requirement R4, to perform at least one “investigative action” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. ~~The proposed~~A VRF of Medium is not inadvertently lowering the ~~identified~~current VRF of High in the former ~~Requirement~~PRC-004-2.1a, Requirements R1 or R3, because ~~the proposed~~this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R4			
	Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

VRF and VSL Justifications – PRC-004-3, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. ~~The proposed~~This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. ~~The proposed~~This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: ~~The proposed~~This 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-004-3, R4	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	~~The proposed~~This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with ~~the requirement.~~this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: ~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which have ~~varying VSLs.~~ ~~The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The former Requirement for the CAP was limited to a High VSL; however, the proposed Requirement R5 is now expanded to the Severe VSL. The lesser VSLs are based on tardiness and are practical and reasonable for the amount of time allotted for completion.~~a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future Misoperations”), PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”), FAC-003, R5 (“…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management”) all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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. An unresolved cause of a Misoperation could contribute the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

VRF and VSL Justifications – PRC-004-3, R5			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
			The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. ~~The proposed~~This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. ~~The proposed~~This Requirement ~~is~~has a Severe VSL for failure to develop the CAP with the ~~Lower VSL~~other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: ~~The proposed~~This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	~~The proposed~~This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with ~~the requirement.~~this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation~~, through~~ as a result of not implementing a Corrective Action Plan, could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: ~~The~~This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-~~2a~~2.1a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which ~~as~~both have a VRF of High. ~~The~~This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future misoperations.") and PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…") which both have a VRF of Medium. The proposed VRF of Medium ~~is~~does not inadvertently ~~lowering~~lower the ~~identified~~current VRF of High in the former ~~Requirement~~PRC-004-2.1a, Requirements R1 and R2, because ~~the proposed~~this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justification – PRC-004-3, R6			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of ~~the requirement~~this Requirement that are not equal in importance and performance.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.		

VRF and VSL Justification – PRC-004-3, R6	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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.
FERC VSL G3 Violation Severity Level 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.~~this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justification – PRC-004-3, R6	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

Table of Issues and Directives

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1460.	For the reasons stated in the NOPR, the Commission will not approve or remand PRC-003-1. (For reference) P 1458. In the NOPR, the Commission identified PRC-003-1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-1 until the ERO submitted the additional information.	PRC-004-3	PRC-003-1 will be retired and replaced by PRC-004-3.
FERC Order No. 693, P 1461.	We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No.	NERC Rules of Procedure, Section 1600 Request for	PRC-003-1 will be retired and replaced by PRC-004-3. The responsibility to address all aspects of a Protection System Misoperation is assigned to the

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
	672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC-003-1 to provide missing information needed for the Commission to act on this Reliability Standard (For reference) P 1459. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.	Data or Information.	owner(s) of the Protection System(s) - the Transmission Owner, Generation Owner, and Distribution Provider. Additionally, further consistency has been achieved by specifying the data reporting requirements for periodic Misoperations reporting based on a continent-wide template. All reporting of Misoperations will be done through a data request according to the NERC Rules of Procedures, Section 1600, Request for Data or Information instead of having PRC-004-3 specify an administrative reporting requirement.

Table of Issues and Directives Associated with PRC-004-2.1a			
Source	**Issues or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1469 (first directive only)	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1. (For reference) P 1466. ISO-NE further requests the Commission to direct NERC to modify PRC-004-1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO-NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO-NE provides the same suggestion with regard to PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1.	PRC-004-3 all Requirements.	PRC-004-2.1a will be retired and replaced by PRC-004-3.The Transmission Owner, Generator Owner, and Distribution Provider own the BES Protection Systems. The owners of BES Protection Systems have been assigned responsibility for this standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-05.1 Protection System (Misoperations)

Additional Ballot and Non-Binding Poll
Now Open from June 20, 2014 through June 30, 2014

Now Available

An additional ballot and non-binding Poll for **PRC-004-3 – Protection System Misoperation Identification and Correction** is open from June 20, 2014 through June 30, 2014.

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 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 Scott Barfield-McGinnis.

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Standards Announcement

Project 2010-05.1 Protection System (Misoperations)
PRC-004-3

A Formal Comment Period Now Open through June 30, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: June 20-30, 2014

Now Available

A 45-day formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is open through **8 p.m. Eastern on Monday, June 30, 2014**.

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 and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 20-30, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2010-05.1 Protection System (Misoperations)
PRC-004-3

A Formal Comment Period Now Open through June 30, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: June 20-30, 2014

Now Available

A 45-day formal comment period for **PRC-004-3 – Protection System Misoperation Identification and Correction** is open through **8 p.m. Eastern on Monday, June 30, 2014**.

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 and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 20-30, 2014**.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Standards Announcement

Project 2010-05.1 Protection System: Misoperations PRC-004-3

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot of **PRC-004-3 – Protection System Misoperation Identification and Correction** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Wednesday, July 9, 2014**.

This standard achieved a quorum and 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
76.98% / 74.53%	75.52% / 77.59%

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 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, Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-05.1 Protection Systems: Misoperations
Ballot Period:	6/20/2014 - 7/9/2014
Ballot Type:	Additional
Total # Votes:	321
Total Ballot Pool:	417
Quorum:	76.98 % The Quorum has been reached
Weighted Segment Vote:	74.53 %
Ballot Results:	The Ballot has Closed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative				
			# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	110	1	68	0.773	20	0.227	0	4	18
2 - Segment 2	9	0.6	4	0.4	2	0.2	0	2	1
3 - Segment 3	102	1	52	0.765	16	0.235	1	7	26
4 - Segment 4	33	1	14	0.667	7	0.333	0	3	9
5 - Segment 5	92	1	42	0.689	19	0.311	2	6	23
6 - Segment 6	52	1	29	0.725	11	0.275	0	2	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	10	0.3	3	0.3	0	0	0	0	7
9 - Segment	2	0	0	0	0	0	0	0	2

9								
10 - Segment 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals	**417**	**6.6**	**218**	**4.919**	**76**	**1.681**	**3**	**24**	**96**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
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	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	

1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Angency)
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski		
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
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	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registed Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group ("PSEG") comments)
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		

1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patrick Farrell (SCE))
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	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton	Abstain	

3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
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	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger		
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Negative	COMMENT RECEIVED
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter	Abstain	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	

3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted by Nebraska Public Power District (NPPD))
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris		
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Orange and Rockland Utilities, Inc.	David Burke		
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	Pacific Northwest Generating Cooperative	Rick Paschall		
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
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	Affirmative	
3	Southern California Edison Company	David B Coher	Negative	SUPPORTS THIRD PARTY COMMENTS - Patrick Farrell
3	Tacoma Public Utilities	Travis Metcalfe	Negative	COMMENT RECEIVED
3	Tampa Electric Co.	Ronald L. Donahey	Negative	NO COMMENT RECEIVED
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Turlock Irrigation District	James Ramos		
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
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	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
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 (FMPA))
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments submitted by FMPA)
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Corporate Compliance)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments entered by Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	

5	Black Hills Corp	George Tatar		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Bridgeport Energy	Cleyton Tewksbury		
5	Caithness Long Island, LLC	Jason M Moore		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	NO COMMENT RECEIVED - (Richard Pienkos)
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke		
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	El Paso Electric Company	David Hawkins		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		
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	Negative	COMMENT RECEIVED
5	Imperial Irrigation District	Marcela Y Caballero		
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 Muncipal 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	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	

5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	COMMENT RECEIVED
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)
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer		
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (PSEG (John Seelke))
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Corporate Compliance)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	SUPPORTS THIRD PARTY COMMENTS - (SCE'sfilled by Patrick Farrell)
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	COMMENT RECEIVED
5	Tampa Electric Co.	RJames Rocha	Negative	NO COMMENT RECEIVED - (Ronald L. Donahey)
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	Turlock Irrigation District	Marty Rojas		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	

5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Barb Kedrowski)
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit		
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 of FMPA.
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
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	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
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	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
				SUPPORTS THIRD PARTY

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	COMMENTS - (Seminole Electric Cooperative's Corporate Compliance)
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	SUPPORTS THIRD PARTY COMMENTS- Patrick Farrell
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 - (Chris Mattson)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Turlock Irrigation District	Amy Petersen		
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Edward C Stein		
8		James A Maenner		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Non-Binding Poll Results

Project 2010-05.1 Protection Systems - Misoperations
PRC-004-3

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-05.1 Non-binding Poll - Protection Systems -Misoperations
Poll Period:	6/20/2014 - 7/9/2014
Total # Opinions:	293
Total Ballot Pool:	388
Summaray Results:	75.52% of those who registered to participate provided an opinion or an abstention; 77.59% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
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 Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
1	City of Tallahassee	Daniel S Langston	Affirmative	

1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
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	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted E Hobson	Abstain	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA - Florida Municipal Power Agnecy)

1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski		
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (OPPD (Mahmood Safi))
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
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	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL NERC Registed Affiliates)
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	

1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS - (Patrick Farrell (SCE))
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	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	

1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
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	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (Cleco)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger		
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russ Schneider)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Abstain	
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Abstain	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	

3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris		
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke		
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric)
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	Affirmative	
3	Southern California Edison Company	David B Coher	Negative	SUPPORTS THIRD PARTY COMMENTS- Patrick Farrell
3	Tacoma Public Utilities	Travis Metcalfe	Negative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		

3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS - (comments submitted by FMPA)
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric

				Cooperative submitted by Corporate Compliance)
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Mattson)
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments entered by Barb Kedrowski)
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar		
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	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Bridgeport Energy	Cleyton Tewksbury		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	

5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Richard Pienkos)
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke		
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky		
5	ExxonMobil Research and Engineering	Martin Kaufman		
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	Negative	COMMENT RECEIVED
5	Imperial Irrigation District	Marcela Y Caballero		
5	JEA	John J Babik	Abstain	
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		
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	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
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)
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer		
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	Proven Compliance Solutions	Mitchell E Needham		
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	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Agree with the comments of Seminole Electric Corporate Compliance.)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	SUPPORTS THIRD PARTY COMMENTS - (filled by SCE's Patrick Farrell)

5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Negative	COMMENT RECEIVED
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ronald L. Donahey)
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Cleco)
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
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	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
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	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative's Corporate Compliance)
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	SUPPORTS THIRD PARTY COMMENTS- Patrick Farrell
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 - (Chris Mattson)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Edward C Stein		
8	Ascendant Energy Services, LLC	Raymond Tran		
8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (47 Responses)
Name (31 Responses)
Organization (31 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
Question 1 (41 Responses)
Question 1 Comments (44 Responses)
Question 2 (38 Responses)
Question 2 Comments (44 Responses)
Question 3 (38 Responses)
Question 3 Comments (44 Responses)
Question 4 (0 Responses)
Question 4 Comments (44 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
In the Composite Protection System definition “Backup protection provided to a remote Protection System is included.” is not clear because it directs the focus from the local protected Element to a remote protection system. Suggest revising this sentence to read “Backup protection provided by a remote protection system by design is included.”
No
The case where manual intervention is required to open a BES interrupting device, but the cause of the Misoperation is located on a Protection System component owned by another Transmission Owner is not addressed in R2. In R1 a special mention to manual intervention is included. Why isn’t a process of notification included in R2 for manual intervention caused by Misoperation of another owner’s protection system?
Regarding Section 5: Background (page 6), additional justification to explain the application of the standard would be beneficial. As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT’s response indicates that UVLS has not been included in the proposed standard’s Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. This rationale is not sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated the same. Note that the SAR for PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS. Requirement R1 does not work for the case where manual intervention to operate the BES device was required. Parts 1.1 thru 1.3 are all ANDS. Part 1.3 requires the Interrupting Device to be operated by the Protection System. This conflicts with the idea in Part 1.1 of MANUAL intervention. If an operator manually opens a breaker because the Composite Protection System does not clear a fault then the Protection System could not have operated the interrupting device. Therefore the threshold R1 would not be met and no identification is required even though the Composite Protection System may have failed-to-trip. Suggest Part 1.3 be revised to read: The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation; or manual intervention was required to operate the BES interrupting device because its Protection System failed to operate. Requirement R1 can be rephrased to provide clarity to the relationship of Parts 1.1 thru 1.3 to R1. Present phrasing has the added phrase, under the following circumstances, following Misoperation where it can ambiguously modify Misoperation. Clearly the intent is to describe the circumstances that a BES device owner has to embark on a process to identify a Misoperation. There are two inputs prior to beginning the process of identification; first the operation of a BES interrupting device occurs and second that the attributes of Parts 1.1 thru 1.3 are met. It would be clearer to place the reference to

Parts 1.1 thru 1.3 prior to the word identify. Suggest Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated, and where such operation conforms to Parts 1.1 thru 1.3, shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation.
Individual
David Jendras
Ameren
Group
JEA
Tom McElhinney
Yes
We disagree witht he 60 day limit in R5 to develop a CAP and think it should be 180 days.
Individual
Chris Scanlon
Exelon Companies
Yes
Yes
Yes
Paraphrasing many commenters from draft 4, Exelon agrees emphasis on due dates from the time of an operation be reconsidered. There is a significant administrative burden imposed by the proposed approach not commensurate with gains in reliable operations. The drafting team can review previous comments to this effect as well as references to the use of “calendar” as used in the PRC-005 supplemental reference to preclude the need to have reviews done by a specific date. We disagree with the SDT response that timeframes as proposed are required to force entities to be diligent about identifying and correcting misoperations.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
R6 -when is a change to a CAP considered failure to implement and therefore a violation of R6 (since R6 both requires implementation of a CAP and allows changes to the CAP)
Individual
David Thorne
Pepco Holdings Inc
Yes
The most recent draft of the proposed standard added a definition for a composite protection system which satisfies our previous concerns.
Yes

We are in agreement that this revision eliminates the identified gap. However, we are still not in agreement that the owner of the interrupting device be responsible for demonstrating compliance with the requirements in the proposed standard, as has been previously stated. This is of particular interest at interface terminals with generator owners.
Yes
None
Individual
Thomas Foltz
American Electric Power
Yes
Yes
No
AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a “slow trip” type misoperation. AEP recommends adding a backup protection example to the application guidelines to illustrate how R2.2 would be applied. AEP recommends adding an example of a breaker failure misoperation to the application guidelines.
As currently written, R5 may be interpreted as requiring the entity to both develop a CAP and complete the evaluation of the CAP’s applicability to other Protection Systems within 60 days. For large entities, or in cases where the evaluation requires equipment outages, completing the evaluation of applicability within 60 days could be impossible. R5 should be revised to clearly state that the entity is only required to develop a CAP within 60 days. There should be an option to include the evaluation within the CAP. This would enable entities to complete the evaluation as part of the CAP and within a time window that is tailored to the scope of the corrective action and quantity of potentially applicable Protection Systems. AEP supports the concept of evaluating a corrective action’s applicability to other Protection Systems. However, the standard requirements provide no means of measuring what is an adequate evaluation. Without this, an auditor could question the adequacy of an entity’s evaluation, decide that the entity’s actions were not an evaluation and subsequently find the entity non-compliant with R5. We believe that the SDT’s Application Guide examples were an effort to demonstrate what would be acceptable. However, the examples are not exhaustive and therefore do not eliminate the audit risk. AEP believes that subject matter experts are in the best position to determine evaluation scope and content. AEP recommends that in lieu of adding additional examples in the Application Guideline, the drafting team should consider the possibility of an auditor invalidating an evaluation. The requirement should be revised so that it places bounds on this scenario and provide entities with certainty in how R5 might be reviewed by an auditor. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. AEP has chosen to vote in the affirmative despite our concerns regarding the CAP and evaluation within R5, and how their compliance would ultimately be determined by an auditor.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes
Individual

Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
No
The 2nd sentence in the definition of Composite Protection System is “Backup protection provided to a remote Protection System is included.” The meaning and intention of this phrase is not readily understood. We suggest that the phrase from previous Draft 4: “Backup protection provided by a remote Protection System is excluded“, is clearer and should be re-instated.
Yes
Yes
Facilities, Section 4.2.1, should have an exclusion for individual dispersed generators, or have its applicability limited to the point where the generators are aggregated to greater than 75 MVA. It is critical for the PRC-004-3 SDT to coordinate with the SDT for Project 2014-01, Standards Applicability for Dispersed Generation Resources, to assure that the new standard will have appropriate applicability consistent with BES reliability.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Yes
Yes
The clarifications and additions to the Application Guide are helpful to the understanding of the standard. We recommend these type of guides be with all proposed Standards in the future.
Thank you for the opportunity to comment.
Individual
John Seelke
Public Service Enterprise Group
No
We agree with the Slow Trip changes. However, the revised definition of Composite Protection System caused much discussion. In the end, we would accept it provided that “a remote” in the second sentence is changed to “another.” With this change, the second sentence would read “Backup protection provided to another Protection System is included.” The backup Protection System need not be “remote” physically; it could be located in the same substation. The phrase “a remote Protection System” would require that the backup Protection System be at a different physical location, which may not be the case as we have just described.
Yes
No

In comments for the prior posting, we addressed a “consistency” reporting issue. See our comments and the SDT’s response in the Consideration of Comments document on pp 27-28 and the SDT’s response which is incorporated into the standard in various places. See the Application Guideline change on p. 31 of the redline version, which included this addition: “The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.” The SDT’s language above still allows entities too much latitude in the classification of an operation as a correct Operation or a Misoperation. The classification of an operation as a correct operation or a Misoperation is step 1 in the process. Only if the operation is determined to be a Misoperation is the cause of the Misoperation investigated (step 2). We suggest this guidance: “If the available evidence IS INSUFFICIENT to classify the operation as a Misoperation PRIOR TO THE INVESTIGATION OF THE CAUSE OF A POSSIBLE MISOPERATION, DO NOT CLASSIFY THE OPERATION AS A MISOPERATION.” • A Misoperation with “no cause found” is not equivalent to a correct operation, which is how an unreported Misoperation is interpreted. If an entity classifies an operation as a Misoperation and goes down that path to investigate the cause, it may well conclude that no Misoperation occurred; however, unless its original Misoperation classification is changed to reflect that result, the reported Misoperations will be overstated. Another entity with an identical operation may decide not to classify it as a Misoperation based upon the data available to it absent an investigation of the cause. For the sake of consistent reporting, the classification decision (correct operation or Misoperation) must be reached without a causal investigation, which only takes place if an operation is classified as a Misoperation.
See the Consideration of Comments document, pp. 76-77. We interpreted that the SDT agreed to our proposed changes to R3; however it was not reflected in this draft.
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
No
Requirements R1 and R2 place the burden on the owner of a BES interrupting device to initiating a review on the operation of the device. This responsibility should fall on the owner of the components of the Composite Protection System that initiated the BES interrupting device to operate. The owner of these components should be just as aware as the owner of the device regarding its operation. In addition, for those entities that are interconnected and who utilize the same BES interrupting device, those entities should have equal awareness of the BES interrupting device status. Therefore, Seminole recommends that the SDT revise Requirements R1 and R2 to require the entity whose components of the Composite Protection System initiated the BES interrupting device to activate.
Individual
Oliver Burke
Entergy Services, Inc.
Yes
Yes
Yes
Entergy agrees with the SERC PCS comments to add Application Guideline examples other than "fixed capacitors", and that the Application Guideline should remain with the standard as a reference.
Group
National Grid

Michael Jones
No
Definitions for “Failure to Trip – During Fault” and “Failure to Trip – Other Than Fault” state that “The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct”. However, requirement R1 asks to identify if “Protection System component(s) caused a Misoperation”. These statements seem to contradict each other. Definition for “Unnecessary Trip – Other Than Fault” provides examples for what it is not. It should also provide examples for what it is, similarly with other definitions.
Yes
Yes
Second part of sub-requirement R1.1 “The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate” seems to contradict with sub-requirement R1.3 “The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation”. R1.1 and R1.3 cannot be met at the same time. An entity which receives notification of the BES interrupting device(s) operation in requirement R3 is allotted between 60 and 120 calendar days. However, the BES interrupting device(s) owner(s) are allotted 120 calendar days. Receiving entity also should be allotted full 120 calendar days counting from the day it receives notification. Requirements R1, R2, and R3 are assuming that an entity will make an attempt to determine the cause(s) of a Misoperation. However, an entity can choose to make no effort until requirement R4 becomes applicable. It is suggested to expand requirements R1, R2, and R3 with the obligation for an entity to make an effort to determine the cause(s) of a Misoperation before requirement R4 takes place.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
Yes
Group
Dominion
Mike Garton
Yes
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
Yes
Yes

Yes
Individual
Roger Dufresne
Hydro-Quebec
Yes
Yes
No
The purpose of the Standard shall be limited only to "Identify and correct the causes of Misoperations of Protection Systems affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC. Requirement R2 The owner of the interrupting device shall share any information he has, that could be used by the other owner of the protection system to determine the cause of the misoperation.
Individual
Don Schmit
Nebraska Public Power District
Yes
No
R2 2.2 states: For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided." Perhaps it would be clearer to state: For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) from the backup protection system owner(s) for which that backup protection was provided." A concern with the gap fix is that the backup protection system owner will not be tracking this as a misoperation because the owner of the interrupting device is the one who had the misoperation yet the backup protection owner must store this notification as part of a misoperation on another entities system which creates an odd and risky compliance tracking situation. It would be unfortunate to get fined for not tracking this even though a misoperation did not occur on your system. This is a difficult situation to address. For a backup protection system owner who operates in back up for a fault on a non BES or non-registered entities system is the notification not required?
No
See suggestion below in 4)
The 1.2 Evidence Retention section states 12 months is the required evidence retention period for the requirements. It also notes that "the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." I would recommend that the evidence retention be longer since it will be difficult to reproduce audit period evidence if it has been discarded. Project 2014-01 Dispersed Generation has noted that PRC-004 needs to be reviewed and updated to direct the industry as to the appropriateness of the BES elements that require misoperation analysis and documentation related to dispersed generation. It is recommended to consider adding these changes rather than issuing multiple versions of this standard unless there is a serious reliability risk with the existing PRC-004 standard. The Draft 5 Application Guidelines states "The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP

and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5." There are concerns that some CAP evaluations including programs for other locations could be open for long periods of time creating significant audit tracking burdens. Is it acceptable in some cases if a CAP for correcting the issue with equipment that misoperated also has an evaluation to only identify other locations that have a similar issue and once other locations are identified the CAP is considered completed and no other audit tracking is required? If this is acceptable this may be beneficial for cases where there is an issue with a large number of similar breakers, relays, communication schemes, potential devices or current transformers that might be widespread on some systems requiring years to replace or update as part of a program or several programs. If the above is not acceptable as the standard is written consider adding a 3rd bullet to R5 to allow a CAP for the specific misoperations and a requirement to identify other locations or allow a declaration that can be used for creating a CAP for other locations that will be considered separately from PRC-004-3. There are still concerns with including manual intervention as part of R1 since most appear to agree it is rare. Can the SDT provide some thoughts on the best way to guarantee that a manual intervention is duly tracked and provided to the protection departments for review? Perhaps dispatch centers need to have a procedure or process that specifically states "any manual intervention for a failed protection system must be reported to the appropriate protection system owner". Would this be considered a reasonable process approach to satisfy the requirements of auditors that the proper misoperation procedures are in place? It may be that the manual intervention requirement is better suited to the SPS, UFSL, UVLS or plant shutdown schemes since those schemes are more likely to allow operators time to react rather than having manual intervention a part of all types of system operations as it is in R1. Perhaps there are cases where an operator has taken action for a transmission line fault or issue that did not clear with primary/secondary/breaker failure or backup remote clearing but I am not aware of any of these cases. It may be better to clarify the types of practical manual interventions that are intended to be covered by the standard or remove it and place it in another standard mentioned above with clarification for the most practical cases where this should be tracked to simplify the misoperation process documents utilities would likely need to have in place. There is concern that an auditor will have the latitude to ask how you guarantee that you are aware and tracked all manual interventions for protection system failures that have taken place on your system in the last audit period and this could be difficult to prove.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration ("ICLP") agrees that the drafting team has made a change for the better in the definition of "Misoperation". The prior version would perhaps lead to more technically-accurate identifications of slow-trip incidents, but made too many assumptions around our capability as a GO to conduct a performance evaluation of the Composite Protection System. We simply do not have the tools or training to determine if high-speed performance is necessary to prevent voltage or dynamic instability. In fact, we may not be aware that a slow trip took place if a secondary or back-up Protection System acts in a manner that masks the condition. We believe that improper operation of a nearby Protection System may be an indication that a slow trip occurred. From that point on, an investigation can ensue that has a chance of success – as our investigative capabilities are designed to address such events. In addition, the bright-line definition leaves no room for a violation assessment based upon a CEA's interpretation that the GO should have deployed sophisticated recorders (DME) or situational analysis tools to prepare for a Misoperation of the type.
Yes
ICLP agrees that there are situations where a relay owned by an external entity may trip a circuit breaker protecting an Element owned by another entity. The interrupting device and relay owners will need to coordinate their investigations in order to resolve the issue – and R2 now ensures that the process will be initiated.
Yes
ICLP found the examples provided in the Applications Guidelines to be helpful. In addition, there is a sufficient diversity in scope that will act as a useful reference in the event that we suspect a Misoperation of one of our Composite Protection Systems may have taken place.

Individual
Jonathan Meyer
Idaho Power
Yes
No
Protection Systems regularly provide backup to the next Element. These backup features are not intended to operate under normal conditions and would not be included as part of an Element's Composite Protection System as we interpret it. The phrase “intended to operate” in 2.2 should be modified to account for operations of another Element’s Composite Protection System that could operate as backup to the normal Composite Protection System for an extreme event.
Yes
Group
Tennessee Valley Authority
Dennis Chastain
Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording that states something similar to the following. In the event that the reporting entity is the victim of a weather related Category 4 or 5 event, 90 days are added to each of the required deadlines for misoperations caused by the weather related event.
Individual
Chris Mattson
Tacoma Power
Yes
No
In the Application Guidelines for Unnecessary Trip – Other Than Fault, the following paragraph seems out of place: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an ’Unnecessary Trip,’ category of Misoperation at the remote terminal.” This paragraph seems to focus on a scenario involving a fault. There is concern that, for a very small number of BES interrupting device operations, an entity could fail to identify (formally document) whether or not its Protection System component(s) caused a Misoperation. If this were to occur, it would likely be associated with apparently benign operations, so the likelihood that a misoperation would have occurred is low. Generally, misoperations garner a lot of attention within an entity, so they are generally hard to miss. Even if no misoperation occurred, an entity could be fined up to the maximum allowable for a Medium VRF and Severe VSL for failing to identify that its Protection System component(s) did not cause a Misoperation. The possibility for fines of this magnitude could drive potentially costly measures to ensure zero defects, even though BES reliability would not be impacted by failing to formally identify that an entity’s Protection System component(s) did not cause a Misoperation. Tacoma Power agrees with the spirit of Requirement R1 but believes that compliance and enforcement should be assessed with failure (or tardiness in) identifying that its Protection System component(s) caused a Misoperation. Basically, if an entity does not determine whether or not a Misoperation occurred, they would be implicitly (by default) saying that a

Misoperation did not occur. During an audit, if a BES interrupting device operation caused by a Protection System is uncovered for which no formal (explicit) identification according to Requirement R1 was made, the entity should only be found non-compliant (or penalized) if the CEA believes that a Misoperation did indeed occur. The purpose of the standard is to “identify and correct the causes of Misoperations of Protection Systems...” Perhaps this issue could be addressed in the Application Guidelines. Even though Requirement R1, Part 1.1, stipulates that “the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate,” to what extent will entities be required to prove that BES interrupting device operations were not caused by a Protection System operation? The potential risk of failing to satisfy Requirement R1 seems high enough that entities may take costly measures to ensure zero defects, out of an abundance of caution, by excessively reviewing BES interrupting device operations. This additional cost could be better served in other areas to support BES reliability. Perhaps this issue could be addressed in the Application Guidelines. In the Application Guidelines for Requirement R1, change “For the case,...” to “For the case in which a...” Furthermore, should this paragraph be included under the Requirement R2 portion of the Application Guidelines? In the Application Guidelines for Requirements R1 and R3, change “The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion” to something like “The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred.” The concern is that the CEA could require an entity to leverage all available data before determining that a Misoperation did not occur. Tacoma Power appreciates the following paragraph in the Application Guidelines for Requirement R2: “A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.” In the Application Guidelines for Requirement R4, Example R4a, was the scheduling activity on 03/24/2014 considered to be the first investigative action pursuant to Requirement R4, or did the first investigative action pursuant to Requirement R4 occur on 4/10/2014? Regarding Requirements R1, R3, and R4, is the date when an entity identifies that its Protection System component(s) caused a Misoperation the date that they officially make the identification? As long as an entity is compliant with Requirement R1 or R3, as applicable, are they afforded some discretion as to the identification date? It seems like the timeline for Requirement R4 should be based on 120 calendar days of the BES interrupting device operation, for Misoperations identified pursuant to Requirement R1, or the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, for Misoperations identified pursuant to Requirement R3. As written now, those entities who quickly identify Misoperations will have compliance obligations under Requirement R4 sooner. On the other hand, an entity that delays officially identifying a Misoperation could be looking for causes ahead of time such that they effectively bypass Requirement R4. Perhaps this issue could be addressed in the Application Guidelines. The objective here is not to make the standard more complicated but to avoid misunderstanding that might surface during an audit. Similarly, regarding Requirement R4 and R5, is the date when an entity determines the cause(s) of a Misoperation the date that they officially make the determination? Perhaps this issue could be addressed in the Application Guidelines. Again, the objective here is not to make the standard more complicated but to avoid misunderstanding that might surface during an audit. In the Application Guidelines for Requirement R6, change “...were postponed due resource...” to “...were postponed due to resource...” If manual intervention in response to a Protection System failure to operate is required, this could imply that both the primary Composite Protection System and remote backup Composite Protection System(s) failed to operate, assuming that remote backup could be configured reliably to detect the fault under the pre-fault power system conditions. Would this condition automatically mean that multiple Composite Protection Systems, potentially at multiple locations (both primary and remote backup), misoperated? Perhaps this issue could be addressed in the Application Guidelines.
Although the term is discussed in the Application Guidelines, consider formally defining the term ”interrupting device.” In Requirement R3, should “BES interrupting device(s)” be “BES interrupting

device”? In Requirement R4, should “the cause” be “the cause(s)”? In Requirement R5, should “a cause” be “the cause” or “the cause(s)”? In the Rationale for R6, change “tivities” to “activities.”
Group
Duke Energy
Colby Bellville
Yes
Yes
Yes
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
Yes
Yes
(1) It would be beneficial if examples in the Application Guidelines had different solutions other than just ‘fixed capacitor’. (2) It would be beneficial and we recommend the Application Guidelines remain with the Standard when published to provide easy reference for users. To provide clarity about the authority of the guidelines, the following note should be included similarly as written in other Standards that include Application Guidelines: "Note: These Application Guidelines for PRC-004-3 are neither mandatory nor enforceable."
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
Leonard Kula
Independent Electricity System Operator
No
We generally agree with the changes to the proposed definition of Misoperation, but do not agree with the proposed addition of the term Composite Protection System. In our previous comments, we expressed our disagreement with the need to create a defined term “Composite Protection System”. By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is therefore redundant. In the comment report, the SDT’s response indicates that the reason for proposing the newly defined term, “Composite Protection System,” is found in the Application Guidelines under the heading “Definitions.”, and therefore no change was made. In the Application Guideline, the rationale provided for introducing this new term is that: [The Composite Protection System definition is based on the principle that an Element’s multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element’s total complement of protection should be considered while evaluating an operation.] We find this rationale insufficient to justify the introduction of the new term since by having the defined term “Misoperation” which covers any failure a Protection System to operate as intended for protection purposes would suffice to include the effect of multiple levels of protection (e.g. redundant systems). In other words, if a Protection System failed to operate as intended or operated unnecessarily, then regardless of the level of protection and which component caused the Protection System to operate, the action/inaction of the Protection System – Composite or otherwise, would constitute a Misoperation. We therefore continue to disagree with the proposed addition of this new term, and suggest that it be removed.

Yes
No
We do not agree with the part on Composite Protection System, for the reasons indicated under Q1, above.
As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT's response indicates that UVLS has not been included in the proposed standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. We do not find this rationale sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated under the same light. Note that the SAR for Project PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT to coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS.
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
Yes
No
Since the last Standard draft, the SDT has added a new example on page 29 of the Application Guideline which states "Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush following a maintenance outage. Only the high-side breaker opens since the low-side breaker had not yet been closed. Since closing the breaker put the transformer bank into service, this is a Misoperation." Although this scenario would be an undesired trip, without the low side breaker closed the transformer will not feed load. With that said, tripping of the high side will not compromise reliability of the BES although it is undesirable. Oncor has not seen a perfect relay that will respond ideally during the reenergization of a transformer with magnetizing current. For the reason just described, the possibility of tripping a transformer unnecessarily during energization (with no load connected) is preferable to desensitizing the protection further such that it might not operate when necessary.
Oncor initially balloted affirmative; however, based on the changes in the Application Guide, Oncor's ballot position has changed. Oncor's comments have been provided for the SDT's consideration (response to Question #3) Oncor requests the SDT please consider the additional comment below: In "R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation." The circumstances mentioned in 1.1 and 1.3 cause confusion when you do not have a protection system component cause the BES interrupting device operation in the event a BES device is operated by manual intervention. Oncor recommends that 1.3 be written to state: The BES interrupting device owner identified that its Protection System component(s) were designed to cause the BES interrupting device(s) operation. The request below is an outstanding request from Oncor's previous comment period: The Extenuating Circumstances process, as outlined on page 30 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the Reliability Assurance Initiative Oncor recommends the evaluation of an Extenuating Circumstance be initially reviewed by Compliance Operations in accordance with the system-wide and regional risk framework, an entity's inherent risk assessment and controls to ensure extenuating circumstances are not evaluated as a

“one size fits all” and findings are determined in accordance with RAI versus an automatic Enforcement path. Furthermore, Oncor recommends the Registered Entity be allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. It is helpful that the Definitions section on p.3 of the standard now says that a Slow Trip classification applies only if the Protection System of another Element was made to operate, but the term “slower than required” should be revised for clarity to read, “slower than the setting specified in the test/calibration instructions.” That is, a Slow Trip should be declared only if the timer is found to be mis-adjusted. Otherwise there’s no way of knowing whether the device at fault was slow or simply failed to function. Uncertainty on this subject is increased by Example 4 on p.25 having been left in its previous (draft 3) wording, “A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation.” This puts us back in the situation of having to decide if a relay acted in, say, ten cycles when five cycles was intended. Having to make such determinations ranges from being unduly burdensome to (for electromechanical relays) impossible, and was the principal reason for our having voted against draft 3 of the standard. It would be better still to state that Slow Trips apply only for TOs, because the issues of concern for this category of Misoperation (e.g. system instability, sequence of tripping) do not apply for generation plants. The description on p.25 of the standard of, “…owner(s) reviewing each Protection System operation,” to determine whether or not, “the speed and outcome…met their objective,” is not typical or appropriate for GOs, and they should not be required to add monitoring systems and design-level personnel to perform a no-value-added function.
No
See our comments above for Example #4. The Application Guidelines should clarify Misoperation analysis scope and purpose differences between TOs (preserve stability and enforce orderly isolation of circuits on a still-live system) and GOs (trip the unit).
We continue to disagree that stating whether or not a Misoperation occurred (per R1) and (under some circumstances) what the cause was (per R3) should be due within 120 days even though identifying the cause may take much longer or may even prove impossible (per R4). That is, the SDT apparently prefers where uncertainty exists to classify events as Misoperations and retract the declaration if later findings show otherwise, while we prefer the present approach of not assuming a Misoperation if evidence to support such a conclusion is lacking. The difficulty foreseen regarding the SDT’s approach is that dated evidence is required in M1 that an entity, “identified the Misoperation… within the allotted time period,” and in M3 that it, “identified whether its protection System component(s) caused a Misoperation within the allotted time period,” while all we may be able to say after 120 days is that we don’t know why an event happened. R4 describes what to do in such a situation, but it does not retract the obligation to provide impossible-to-obtain evidence satisfying M1 and M3.
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
The composite protection definition involving backup to remote protection does not completely make sense when coupled with the "slow trip" definition. The "total compliment" description in the

Composite Protection System definition indicates that remote backup protection is included in the "total compliment". If the remote backup protection operates instead of the local, primary protection for an element, the "total compliment" collectively functioned to protect the element. Calling this situation a "misoperation of the Composite Protection System" is contradictory to stating that the total compliment collectively functioned as intended. Also, how does this make sense for the protection systems at generating facilities? What does 'backup protection provided by a remote protection system' mean for generating facilities? The slow trip definitions are still confusing. Are there multiple Composite Protection Systems that need to be considered when determining if a trip is a slow trip? The "its operating time" references are indefinite in the definition. Consider making the slow trip definition either one of the following or a combination of the following OR statements: "a composite protection system operation that is slower than required or slower than designed or slower than desired or slower than the intended design". There is a fundamental flaw in the definition of misoperation. A misoperation is recognizable any time any part of a protection system design fails to operate as intended by the design, regardless of the existence of a redundant, remote, or back up protection scheme. The fact that something did not operate properly should indicate that a misoperation has occurred. The addition of the adjective “reportable” simply classifies the types of misoperations that are to be reported. The comment above does not address a requirement governing the actual reporting.
No
There is a problem with R2.2. One entity does not necessarily know whether or not another entities' Element has an abnormal condition. This notification of other entities for an explained operation of my interrupting device and my protection system should not be required. It is acknowledged that this was an attempt to eliminate the gap described above, but it is contrary to the Composite Protection System collectively functioning as intended to protect an element.
Yes
Application Guidelines: Overall, this document is very good in addressing the process.
a) The multiple timing process periods are an added burden and still unclear in the standard. However, the application notes do provide some guidance {R3}; b) The wording in R3 of the Process Flow Chart on the last page of the draft standard should match that of the requirement R6 (change "greater" to "later" in the chart). There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork.
Individual
Patrick Farrell
Southern California Edison Company
No
SCE disagrees with the explanation of and rationale for the "Composite Protection System" for the following reasons: 1. If an interrupting device is tripped due to misoperation of another device not owned by the owner of the interrupting device, then the owner of the interrupting device will be unaware of this issue until the formal notification of the event to all the owners of the composite protection system is made. One of the reasons for the misoperation of the other device could be a failure to trip. 2. In the case above, the owner of the interrupting device would not be able to validate Requirement 1.3: “The BES interrupting device owner identified that its Protection System Component caused the BES interrupting device(s) operation.” Therefore the owner would not be able to and may not be required to notify other entities owning the composite protection system. The root cause would either not be analyzed or the analysis would be delayed.
No
In the case where a non-performing protection system has caused a tripping device to operate, the non-tripping device could be ignored, resulting in the problem not being mitigated and eventually posing a greater risk to the composite protection system. Assuming that the owner of the system notifies the other entities owning the composite protection system, the time window of 120 days to notify would be too long in order to promote effective and efficient resolution of the problem. Notification should be within a week of the occurrence of event in order to allow the other impacted entities to review, analyze, and communicate with each other in order to perform a root cause analysis and determine a corrective action plan.

Yes
With respect to Requirement 5 on the Corrective Action Plan requirements, we are concerned that an entity's declaration that no corrective action will be taken without supporting evidence, could leave a system problem unresolved. The decision that a Corrective Action Plan is unnecessary, or the development of a Corrective Action Plan, are both complex actions that should be done jointly by respective owners of the composite protection system in a consensus-building manner. The failure to reach consensus on Correction Action Plans can leave the problem unresolved.
Group
ACES Standards Collaborators
Jason Marshall
Yes
We agree with the changes.
No
(1) We continue to believe that this standard has been overly complicated by including administrative elements such as reporting information to third parties. The reporting does little to nothing to support reliability. The real value is in analyzing the Protection System operations and correcting any errors. Is there any indication that registered entities are not communicating to co-owners of the Composite Protection System that a potential misoperation occurred? If not, (and we have seen no such evidence) why does this administrative requirement that clearly meets multiple P81 criteria (administrative and reporting) rise to level of needing to be enforced with financial penalties? Barring such evidence, we simply do not see how we can support such a requirement. Clearly, the application guidelines spell out what is necessary. We recommend that the drafting team perform a study to determine if there is a true reliability need for communicating with co-owners of Composite Protection Systems. If the drafting team cannot provide data or statistics indicating a gap in reliability, then we recommend striking the administrative tasks from the requirement. (2) The existing standard was fairly simple and coupled with the new definition of Misoperation largely addresses the scope of the SAR. All that is really is needed for this standard is a requirement to evaluate Protection System operations, identify if the Protection System operation was a misoperation and then to develop a Corrective Action Plan to prevent future misoperations. Six requirements create more complication than what is necessary.
Yes
(1) We agree that the Application Guidelines include improved examples and did clarify the intent of the drafting team. Furthermore, we support the intent in the application guidelines. However, in some cases, the intent of the drafting team and the language of the requirements simply do not align. For example, language was inserted into the Requirement R3 discussion on page 31 to clarify that a registered entity is "to classify an operation as Misoperation if the available information leads to that conclusion" and "allows an entity to classify an operation as a Misoperation if an entity is not sure." Neither Requirement R3 nor Requirement R1 language provide this flexibility and is thus inconsistent with the language in the application guidelines. R1 and R3 are both very clear that the responsible entity has 120 days (for R3 or the later of 60 days after notification) to identify whether its Protection System operations were a Misoperation. This language is definitive. We do not see how this language allows an entity to classify an operation as Misoperation if it is not sure. Again, the requirement language states clearly that the responsible entity has to identify whether its Protection System components result in a Misoperation. There is no room in the language of the requirement for uncertainty. This further leads to a problem with R4 because R4 would require R1 and R3 to be violated since both require determination of whether a Misoperation occurred and R4 identifies a situation that can only occur after a violation of R1 or R3. Even the last Severe VSL for both R1 and R3 supports our argument. Failure to identify a whether or not a Protection System operation is a Misoperation is a Severe VSL. We suggest the drafting further refine Requirements R1, R3, and R4 collectively to match the intent demonstrated in the application guidelines.
(1) Example 3 on page 25 should be updated. The first sentence is inconsistent with the proposed definition of Misoperation. A failure of a line's Composite Protection System to operate as quickly as intended is only a Misoperation if another Element's Composite Protection System operation. Please append the following clause to the first sentence: "if another Element's Composite Protection System operated." (2) The VSLs for R3 rely only on the 120 day portion of the language in the requirement.

They do not include the "later of" language relying on 60 days if more than 60 days has passed since the original Protection System Operation. We suggest the VSLs should be updated accordingly reflect the requirement in totality. (3) To avoid requiring a registered entity from providing all BES interrupting device operations, the Compliance Assessment Approach for R1 in the RSAW needs to be modified to be consistent with the requirement and the evidence request section. The auditor should only sample BES interrupting device operations that meet the criteria Requirement R1 Part 1.1 through 1.3 and is provided as evidence in the evidence requested section. Please add "that meet criteria Requirement R1 Part 1.1 through 1.3" after "interrupting device operations" in the first and second rows of the RSAW's Compliance Assessment Approach for R1. (4) Please update the RSAW's Note to Auditor section to review the Application Guidelines section for Requirement R2 for small entities as well as vertically integrated utilities. The Application Guidelines make clear that small entities with a single protection engineer are not expected to provide notification requirements between the GO, TO and DP because they would already be aware since they evaluate all Protection System operations including transmission and generation. (5) Thank you for the opportunity to comment.
Individual
Mahmood Safi
Omaha Public Power District
Yes
Yes
Yes
The Omaha Public Power District (OPPD) is still concern with the 60-day requirement to develop a Corrective Action Plan (CAP) for an identified misoperation. This timing is not practical, and depending on the time of the year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs. Also, the first bullet under R5 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies. OPPD proposes that 180 days (6 months) is a sufficient timeframe to practically develop a CAP addressing both operational and budgetary coordination.
Group
Florida Municipal Power Agency
Carol Chinn
Yes
FMPA's primary concern with the previous version of this definition centered around the ability to accurately classify the events and show evidence as appropriate. FMPA agrees the revised versions of "Slow Trip – During Fault" and "Slow Trip – Other than Fault" are more specific and thus easier to consistently apply. However, we do not believe the revised versions are going to result in events being classified the way the SDT desires. We are voting yes for this item because our primary concern is addressed. The SDT should reconsider these revisions, though, in light of the following – the revised versions have nothing to do with the designed, set, or normal operating time as specified by the relay manufacturer/settings. We believe the intent of these two categorizations is to identify relay misoperations for which a relay, interrupting device, or relay setting which was intended to operate at a particular speed, instead operated at a slower speed / in a longer time. Just because a relay from a different Element's Composite Protection System operates does not necessarily mean this event was undesired, unnecessary, or unintended. As stated in our last comments we refer back to the core issue that the protection system performance should be measured against a company's relay setting philosophy. We also note that the Application Guide still refers to this event in "Example 3" as "A failure of a line's Composite Protection System to operate as quickly as intended…". The application guide also still includes language regarding "slower than previously identified as being necessary to prevent voltage or dynamic instability".

1. FMPA does not feel our previous comment regarding notification to affected entities was properly understood. This comment was offered to R2 in the previous round of comments. We understand the way the document is intended to flow, but our main concern is the relay event records are preserved by all entities indefinitely – for many Utilities a special trip must be made to the substation to download the event records. What prevents the Owner of a BES interrupting device that operated from taking the full 120 days to conduct their review without saying anything to the other affected owners, only to find upon request of further evaluation that those entities no longer have the relay event records necessary for the evaluation? At minimum the entity Owning the BES interrupting device should advise the other affected Protection System owners that the investigation is under way at the earliest time they determine those entities are affected, to allow the entities to be prepared with data should they be notified in accord with R2. FMPA does not see how the gap regarding a case where an interrupting device did not operate has been addressed. Reading R1 and R2 again, it still appears that all triggers for activity are based on interrupting device operation, and we see no mention of a case where an interrupting device did not operate. While we can see that requiring actions in the standard based on relay targets, for example, would be challenging to enforce, we would have expected at least a statement, something to the effect of “Or if the entity otherwise becomes aware that a Composite Protection System it owns operated without an associated interrupting device action”.
Yes
FMPA appreciates the changes to the Application Guide and does feel the additional specificity was beneficial. We do, however, feel some sections are inconsistent with the revised Requirements and definitions in the standard. See our comments on the definition of “Misoperation” above. There may be some additional changes that are needed to the Application Guide to ensure it fully supports the revised Standard.
2. FMPA does not feel our previous comment regarding the inherent problems with the concept of comparing Protection System performance to a single set of generic categories as tied to compliance was addressed. We feel many of the issues and challenges in this revised standard would easily be addressed by allowing entities to compare the performance of their relays with their Protection System Design Philosophy. In the absence of a mandatory electric reliability standard, this is how Utilities would determine “mis-operations” – did the Protection System/component perform according to the intended design? 3. In the Facilities section – what is the reason PRC-004-3 cannot use the same description of “Protection System” as PRC-005-2? Would these two standards not inherently be designed to cover the very same Facilities? 4. FMPA accepts the SDT’s revised definition of Composite Protection system which no longer singles out step-distance/intentional remote backup schemes. However, we in general do not agree with the use of Composite Protection System in the standard. This term is being used to reduce what is considered a “Misoperation”. While FMPA supports more relaxed Requirements for mitigating/remediating a Misoperation when another part of the Composite Protection System successfully prevents any negative impact to the BES, a Misoperation is still a Misoperation. If the goal is to keep statistics on how we are doing as an industry, we need to tie those statistics to basic characteristics that are less subject to interpretation and change. Misoperation should still be tied to the failure of equipment. The fact that a different part of the Composite system properly functioned is additional information. Again, we support the idea that a properly designed Composite Protection system should mean an entity does not necessarily need to make changes, but the Misoperation should still be tracked. 5. What is the reason the defined Glossary term “Fault” has been replaced with “fault” throughout the document?
Individual
Louis C. Guidry
Cleco
Yes
Yes
Yes

Cleco will continue to vote "Negative" as long as the SDT continues to support in R1 and R2 the deadline of 120 days to determine if an operation is a misoperation. There should be exceptions built into the standard when there are circumstances that create numerous outages such as ice storms or hurricanes. For example; In FAC-003, a footnote allows for circumstances that are beyond the control of the Registered Entity. Also, the standard should apply to all protection systems and the SDT should not exclude SPS or RAS.
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
No comments
No comments.
Texas Reliability Entity is voting Negative on this standard due to the concern that the reliable operation of the BES is not ensured by this standard (as written) because the allowable time periods for investigating and correcting are too long and investigative actions are not required before R4. Please consider the following comments and recommendations. 1) Recommend changing the allowable time for identification of a Misoperation to 60 days for R1 and R2. The 120 identification period (in R1 and R2) coupled with the additional allowance in R3 of 60 days means a Misoperation may not be determined up to 179 days after the interrupting device operation. The risk to the BES is still undetermined during this time period and actions should be taken to identify if a Misoperation occurred more expeditiously. 2) Suggest revising language in Requirements 1 and 3 to include investigative actions: [each entity] “shall perform investigative actions to identify whether its Protection System component(s) caused a Misoperation” The proposed language would clarify the expectation that investigations are on-going prior to R4. As written, the standard conceivably allows for a period of up to 120 days before investigative actions are performed. Although the application guidelines for R4 states that an entity “is expected to use due diligence in taking investigative action(s) to determine the cause(s)…” and that R4 “provides the entity a mechanism to continue its investigative work…” the standard does not require an entity to do investigative work before R4. 3) Recommend changing the performance of investigative actions to at least once every calendar quarter in R4. If a Misoperation is confirmed (through steps taken in R1 – R3) then the risk to the BES continues until such time as a cause is found and can be corrected. The application guidelines state that periodic investigative action minimizes compliance burden and focuses the entity’s efforts on determining cause, Texas Reliability Entity asserts that the time period of at least one investigative action every two full calendar quarters (180 days) is not adequate to protect reliability. 4) In order for R4 to be measurable there should be a stated time horizon (per NERC’s Acceptance of a Reliability Standard, Item 7, first bullet). The investigation may end either by identification of the cause of the Misoperation or a declaration that no cause was found. Suggest adding requirement to either determine the cause or make the no cause found declaration within 365 days after interrupting device operation. 5) The investigation and CAP timelines (as written) exceed 12 months so the evidence retention period of 12 months is insufficient. Evidence of investigative actions may be disposed of before corrective action is completed; meaning that a full record of an interrupting device operation may not be available for review by the CEA. In addition, the 12 month evidence retention schedules for R5 and R6 mean that an entity may not have any evidence to prove compliance to a CEA during an audit (which can be several years after a Misoperation).
Individual
Bill Temple
Northeast Utilities
No
The part of the Composite Protection System definition “Backup protection provided to a remote protection is included” is not clear because it switches focus from the local protected element to a remote protection system. We suggest revising this part to say “Backup protection of the element provided by a remote protection by design is included.”
Yes

Yes
The examples provided in the application guideline should be clarified when talking about unnecessary trips. It should be made clear that if any portion of a Composite Protection System designed to protect one Element operates for a problem on another Element is considered a Misoperation.
The Unnecessary Trip definitions as written are unclear and seem to indicate that the total compliment of the Composite Protection System. Suggest the following clarifications; Unnecessary Trip – During Fault – An unnecessary operation of any Protection System of a Composite Protection System for a Fault condition on another Element. Unnecessary Trip – Other Than Fault – An unnecessary operation of any Protection System of a Composite Protection System for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.
Individual
John Brockhan
CenterPoint Energy
No
CenterPoint Energy recommends adding wording to the definition to address the direct interrelationships between Misoperation categories, especially the “Slow Trip – During Fault” and the “Unnecessary Trip – During Fault” categories. For these two categories, an operation of an un-faulted Element’s Composite Protection System occurs. This interrelationship is detailed in the Application Guidelines which states the following for the “Slow Trip – During Fault” category: “In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element. If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip – During Fault” category of Misoperation at the local terminal.” In addition, the Application Guidelines states the following for the Unnecessary Trip – During Fault: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault” category of Misoperation at the remote terminal.” CenterPoint Energy suggests adding clarifying wording at the end of the “Slow Trip – During Fault” and the “Unnecessary Trip – During Fault” categories: 3. Slow Trip – During Fault – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System, providing it is not determined to be an Unnecessary Trip – During Fault. 5. Unnecessary Trip – During Fault – An unnecessary Composite Protection System operation for a Fault condition on another Element, providing it is not determined to be a Slow Trip – During Fault.
CenterPoint Energy recommends deleting the proposed Requirement R2.2. Based upon the changes made to the Composite Protection System definition and the proposed wording of Requirement R2.1, CenterPoint Energy believes the proposed wording of Requirement R2.2 related to backup protection is unnecessary. The Composite Protection System definition now states that “Backup protection provided to a remote Protection System is included.” This, along with Requirement R2.1 stating “notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances” and Requirement R2.1.2 stating “The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation”, provides for the notification intended by Requirement R2.2.
No
CenterPoint Energy recommends adding additional examples to help provide consistent reporting of Misoperations. Examples for Breaker failure events (stuck breaker) and additional examples of the more common “Unnecessary Trip – During Fault” category would be helpful. Additional examples would help clarify the interrelationship between the “Slow Trip – During Fault” and the “Unnecessary Trip – During Fault” categories. The following comments and additional examples are provided for consideration: Example 1e: The Composite Protection System for a bus does not operate during a bus fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During

Fault” Misoperation of the bus Composite Protection System. Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical fault clearing time for a line fault in conjunction with a breaker failure (stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element’s Composite Protection System. If a generating unit’s Composite Protection System operates due to instability caused by failure of a breaker's Composite Protection System, it is not an “Unnecessary Trip – During Fault” Misoperation of the generating unit’s Composite Protection System. This event would be a “Slow Trip – During Fault” Misoperation of the breaker's Composite Protection System. Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems due to dynamic stability reasons. The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a fault on this line, the two pilot systems fail to operate; and, the time-overcurrent scheme operates clearing the fault with no generating units or other Elements tripping (no over-trips). This event is not a Misoperation. Example 3d: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with the two independent high-speed pilot systems. During a fault on the line with the two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-overcurrent scheme operates clearing the fault however, another line in the system trips (over-trips). The trip of the other line in the system is not an “Unnecessary Trip – During Fault” Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a “Slow Trip – During Fault” Misoperation, although the analysis and Corrective Action Plan would address the two pilot schemes failure to trip. Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared fault on a different line is a Misoperation. The fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip of the line protection; therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation. Example 5c: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with two independent high-speed pilot systems. During a fault on the line with two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-overcurrent scheme operates clearing the fault and, in conjunction, another line in the system trips (over-trips). The trip of the other line is not an “Unnecessary Trip – During Fault” Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a “Slow Trip – During Fault” Misoperation, although the analysis and Corrective Action Plan would address the schemes failure to trip. Additionally, in the Application Guidelines, it appears the following paragraph at the end of the “Unnecessary Trip – Other Than Fault” examples is misplaced and could be deleted: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal.” CenterPoint Energy recommends adding the following wording as the last two paragraphs at the end of the examples for “Unnecessary Trip – During Fault” examples to parallel the wording for the “Slow Trip – During Fault” category: In analyzing the Protection System for Misoperation, the entity must also consider the “Slow Trip – During Fault” category to determine if an “slow trip” applies to the Protection System operation of an Element other than the faulted Element. If a coordination error was at the remote terminal (i.e., set too fast), then it was an " Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

(a) In the Application Guidelines, CenterPoint Energy recommends changes to account for high-speed tripping for internal transformer faults by other types of protection systems (e.g., sudden pressure) that are not specifically included in the proposed definition of Composite Protection System. The following additional wording at the end of Examples 1a and 1b is suggested: Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer fault is a Misoperation unless other protection schemes (e.g., sudden pressure) operated. Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System or other protection schemes (e.g., sudden pressure) operated. (b) The proposed Requirement R4 wording currently includes the following: “…shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes…”. CenterPoint Energy understands this wording is to provide a mechanism to continue investigative work to determine the cause of a Misoperation when the cause cannot be determined during the allotted time periods in Requirements R1 or R3. CenterPoint Energy recommends additional wording to allow the investigation to be completed in the quarter that the misoperation occurs (“partial quarter”) for cases where the investigation and tests, including any needed outages< can be completed in the partial quarter and suggests the following wording: “…shall perform investigative action(s) to determine the cause of the Misoperation at least once during the partial quarter when the misoperation occurs or every two full calendar quarters after the Misoperation was first identified, until one of the following completes…”.
Individual
Don Cuevas
Beaches Energy Services
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
Yes
No
Tri-State remains concerned with situations where individual components are jointly owned. The SDT’s response “While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results” appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated “Compliance Entity”. Typically compliance contracts take some time to come to fruition. Is it the drafting team’s intent that misoperations be reported by multiple entities in this situation until a contract is finalized?
Yes
In response to Tri-State’s previous concern to the review and reporting of operations of jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. The SDT stated “While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results” appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated “Compliance Entity”. Typically compliance contracts take some time to come to fruition. Is it the drafting team’s intent that misoperations be reported by multiple entities in this situation until a contract is finalized?
Group
SPP Standards Review Group
Robert Rhodes
Yes

Yes
Formatting in recent standards has tended toward using bullets in lieu of subparts. The drafting team is encouraged to follow this practice in Requirement R2. Note that there are bullets in Requirement R5. Delete the 2nd 'when' in the 6th line (clean copy) of the Rationale Box for Requirement R2.
No
We note that the drafting team included several additional examples in this version of the standard and we certainly appreciate that. We would however suggest that the following examples would provide further clarification: 1) an example which illustrates that a properly coordinated breaker failure operation does not equate to a slow-trip operation, 2) a backup protection example to provide clarity on how Requirement 2, Part 2.2 would be applied and 3) an example of a breaker failure Misoperation. We noted that the drafting team reverted to the non-capitalized 'fault' throughout most of the Application Guidelines. Yet in the listing of items that characterize a Misoperation on Page 23 (clean copy), the drafting team maintained the capitalization from the previous draft. Can the drafting team provided clarification on the proper use of the term? In the 1st line under Unnecessary Trip – Other Than Fault on Page 26 (clean copy), delete the comma between 'to' and 'power'. Hyphenate 'out-of-service' in the paragraph following Example 7a on Page 27 (clean copy). Hyphenate 'high-side' in the 3rd line of Example 7b on Page 27 (clean copy). Replace 'voltampere-reactive' with 'VAr' in the 3rd line of the paragraph under Non-Protective Functions on Page 27 (clean copy). We appreciate the explanation provided in the Extenuating Circumstances section. However, we believe that the standard should go beyond what is provided in the Sanction Guidelines. Why should an entity be held in violation in the event of multiple operations on its system during a natural disaster? There may not be an actual Misoperation but because an entity simply doesn't meet the purely administrative requirement of getting the evaluation done within a prescribed number of days, a violation has occurred. Recognition should be given in the standard for such events which withhold declaration of any potential violation until the entity has had sufficient time to 1) deal with the crisis at hand of rebuilding its system and 2) then performing the evaluations to determine if Misoperations occurred. This flies in the face of being innocent until proven guilty. In the 2nd paragraph below Example R1a, insert 'where a' such that the 1st line reads: 'For the case, where a BES interrupting device…' In the 4th paragraph below Example R1a, insert 'the' in the 7th line between 'if' and 'entity'. In the 1st paragraph below Requirement R3, break the two sentences in the 7th-9th lines (clean copy) into two separate sentences such that it reads: 'The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation and continue its investigation under Requirement R4.' Bracket the 's' in 'CAP(s)' in the 4th line of the 2nd paragraph below Requirement R5 on Page 33 (clean copy). Insert a 'to' between 'due' and 'resource' in the 4th line of the 2nd paragraph of Example R6c. Regardless of the outcome of the capitalization of 'fault', it should be capitalized in the 1st sentence of Example R6d just like the 1st words of all the other examples given.
UFLS is mentioned in 4.2.2 of the Applicability Section but there is no mention of UVLS. Should it be included here? We would suggest that the drafting team consider incorporating the evaluation of the CAP's applicability mentioned in the first bullet under Requirement R5 into the CAP itself. This falls in line with the second bullet in the Requirement which is included in the CAP and gets the burden of making the evaluation concurrently with the development of the CAP out of the way. The evaluation could delay the completion of the CAP. References to days should be calendar days and they should be hyphenated; for example 30-, 45-, 60-, or 120-calendar days. Similarly, references to months should be treated in the same manner; for example 12-calendar months.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
Yes

ERCOT is concerned about Requirement 1 that allows entities 120 days to identify a misoperation. ERCOT believes this might negatively impact the reliability of the grid. Currently, entities have the responsibility to analyze disturbances to identify misoperations. A misoperation could indicate a greater threat to reliability and that threat could exist, unknown, for several months while entities make determinations if operations are truly a misoperation. The responsible entity under the new Standard will track misoperations and develop Corrective Action Plans (CAPs). There is no responsibility for the entity to share that information with Reliability Coordinators who have the responsibility for the wide area view of their Reliability Coordinator area. ERCOT is also concerned that while the responsible entity may develop CAPs, there is no responsibility of coordination of the CAP with other potentially affected entities. ERCOT is therefore recommending the following: R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 24 hours, identify whether its Protection System component(s) caused a Misoperation on an element that is part of an Interconnection Reliability Operating Limit under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 2 business days, identify whether its Protection System component(s) caused a Misoperation on an element at 200 kV or more under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 2.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 2.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 2.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R3. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 5 business days, identify whether its Protection System component(s) caused a Misoperation on an element that is a BES element under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 3.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 3.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 3.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the CAP developed in R5, to the Reliability Coordinator with the expected date of completion, how the Composite Protection System will operate until the CAP is completed and detailed information of how the entity will coordinate the CAP with other affected entities if applicable.
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
Yes
BPA believes that there is one other gap that has not been identified. This is the case where a TO, GO, or DP owns a BES interrupting device that operates, but does not own any of the Composite Protection System. This is a real scenario. In this situation, the owner of the BES interrupting device is not subject to R1 because R1.2 is not true, i.e. the owner of the BES interrupting device does not own all or part of the Composite Protection System. Likewise, the owner of the BES interrupting device is not subject to R2 because R2.1.1 is not true, i.e. the owner of the BES interrupting device does not share ownership of the Composite Protection System -- they don’t have any ownership of the Composite Protection System. With the owner of the BES interrupting device not subject to R1 or

R2, the operation of the BES interrupting device would not be investigated. BPA suggests that this problem could be remedied with a slight change in language to R2.1.1 as follows: “The BES interrupting device owner does not own any of the Composite Protection System or shares the Composite Protection System ownership with any other owner.” This change would require an owner of a BES interrupting device that does not own any of the Composite Protection System to provide notification of the operation to the owners of the Composite Protection System within 120 days per R2.1 so that they could then investigate the operation.
Group
Operational Compliance
Dianne Gordon
No
A. The Application Guidelines provide some clarity on the difference between "Slow Trip - During Fault" and "Unnnecessary Trip - During Fault". However, these definitions may still not be entirely clear. B. Quoting Requirement R1...p.31 of Application Guidelines "When Elements are isolated from the BES and undergoing maintenance.....not subject to the standard....provided they do not result in the operation of...part of the BES." This statement and Example 6e (#6 of Misoperation definition), p.28 (at first glance anyways) may be at odds.
Yes
Yes
Individual
Venona Greaff
Occidental Chemical Corporation
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
Generally do not like the phrase "composite", would prefer that Protection System just have a solid definition. I appreciate that is the dilemma here and my specific suggestion be to delete the word composite throughout.
No
The way the M2 is written is overly prescriptive and limiting on what might be acceptable way to show the coordination between entities. The measure seems to written like a requirements. Prefer the previous language.
Yes
still have trouble with how the word composite is being used, but do agree that the guidelines provide clarity on the drafting teams intent, unsure the compliance impact on the requirements
Generally feel that the requirements should be the sole place where the actual compliance requirements appear. Lot of information in measures, application guidelines, definitional changes that are not technically requirements but may be treated as such depending upon the audience.
Individual
Michelle Clements
Wolverine Power Supply Cooperative, Inc.
Yes
Yes
Yes

Wolverine's position is that the PRC-005 standard sufficiently covers the maintenance and testing requirements for protection systems. Because of this maintenance performed, it is not necessary to perform a detailed engineering analysis of every BES protection system operation. Wolverine's position is to only perform an engineering review of protection system operations if there is an apparent misoperation, for example, an over reach condition, failure to trip, etc. These are easily identified by transmission operators if only the correct facility cleared. To use a protection system operation to verify if a primary and backup protection system work properly seems to conflict with the requirement in PRC-005, which is written to ensure protection systems are maintained so they work properly.

Consideration of Comments

Project 2010-05.1 Protection System (Misoperations)

The Project 2010-05.1 standard drafting team ("SDT" or "drafting team") thanks all commenters who submitted comments on the draft 5 of PRC-004-3 Reliability Standard. This draft Reliability Standard was posted for a 45-day public comment period from June 20, 2014 through July 9, 2014. Stakeholders were asked to provide feedback on the draft Reliability Standard and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 136 different people from approximately 101 companies representing all 10 industry segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the NERC 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 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary of Changes

The drafting team determined certain non-substantive changes should be made in response to comments. The summary below provides an overview of the clarifications made to the draft PRC-004-3 Reliability Standard.

Definitions

The second sentence of the definition of "Composite Protection System" was clarified by changing the wording from an "inclusionary" to an "exclusionary" statement.

> "The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded."

The drafting team contends that this change is non-substantive because it is a clarifying rewording of the intent of the definition that was requested by commenters. The phrase for backup protection provided "to a remote Protection System" - "is included" is better described "by a different Element's Protection System" - "is excluded". Backup protection that is a part of the Protection System under study is "included." however, it is not intended that the "backup protection provided by a different

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Element's Protection System(s) to be" included. If this were the case, by definition, there would be very few identified Misoperations.

Requirements

Requirement R1

Requirement R1 was clarified based on comments. The drafting team moved the clause "under the following circumstances" (referring to Parts 1.1, 1.2, and 1.3) and added the clause with the clarifying reference to the Parts "under the circumstances in Parts 1.1 through 1.3" before the "shall" statement. The reason for moving the clause is based on comments noting that with the placement at the end of the requirement grammatically modified "Misoperation" and not the "BES interrupting device." The drafting team agreed that moving the text would grammatically modify "BES interrupting device" without changing the meaning of the Requirement.

Requirement R1, Part 1.3 was clarified based on a comment revealing an unintentional omission in the circumstances in which an entity is required to review a BES interrupting device operation. The Requirement has three conditions for which the applicable entities must initiate a review of its Protection System to identify whether its Protection System component(s) caused a Misoperation. Part 1.1 has two conditions:

1. A BES interrupting device operation caused by a Protection System; or
2. A BES interrupting device operation caused by "manual intervention" in response to a Protection System failure to operate.

The comment revealed that in Part 1.3 that there was no circumstance for "manual intervention" that is included in Part 1.1. This unintentionally means that all three Parts (i.e., 1.1-1.3) could not be properly satisfied for the "manual intervention" circumstance ("was true") in Part 1.1. Because of this, an applicable entity could reason that the "manual intervention" circumstance was not caused by an actual Protection System component per se. Since the BES interrupting device operation did not satisfy all the circumstances ("were true") of the three Parts, the entity could reasonably justify that the operation does not need to be reviewed because Part 1.3 would not be true. The drafting team did not intend for Part 1.3 to create this circumstance. The drafting team agreed that this circumstance omission technically created an unintended condition in Requirement R1 where it is obvious that Part 1.3 should have included the "manual intervention" circumstance. Therefore, the drafting team inserted the phrase "or was caused by manual intervention in response to its Protection System failure to operate" to accurately account for the "manual intervention" condition specified in Requirement R1, Part 1.1 to make the intention clear to industry.

Requirement R2

Requirement R2, Part 2.1 received the same clarification to include "manual intervention" as Requirement R1, Part 1.3 based on comments. The intention is to notify other Protection System owners when either the BES interrupting device operation is caused by a Composite Protection System or "by manual intervention in response to a Protection System failure to operate."

Additionally, the drafting team inserted the term "BES" in Requirement R2, Part 2.2 before "Element" to clarify that backup protection was provided for a condition on another entity's "BES Element" and not on another entity's non-BES Element. This is consistent with the objectives listed in Section 5, Background of the draft PRC-004-3 Reliability Standard.

Requirement R3

No changes were made to Requirement R3.

Requirement R4

Requirement R4 was clarified by adding a parenthetical "(s)" to the second occurrence of "cause" for consistency with a previous occurrence in the Requirement.

Requirements R5 and R6

No changes were made to Requirements R5 and R6.

Measures M1 through M6

No changes were made to Measures M1 through M6.

Compliance

The clause "a minimum of" was added to the paragraphs pertaining to Requirements R1 through R6 to clarify that the evidence retention periods stated in the Compliance section are minimum retention periods. The drafting team made another clarification based on a comment about how the evidence retention period is applied to Requirements R1, R2, R3, and R4. To clarify that the minimum retention period applies to each Requirement, the drafting team added the clause "following the completion of each Requirement." Last, the drafting team clarified that evidence from R1 through R4 must be retained with the Corrective Action Plan.

Violation Risk Factors and Violation Severity Levels

There were no changes to Violation Risk Factors. The drafting team deleted "or not" from each of the Requirement R1 Violation Severity Levels. Requirement R1 does not mandate that an entity make a determination of whether "or not" an operation is a Misoperation. The reliability activity in Requirement R1 is to "identify whether its Protection System component(s) caused a Misoperation." The VSL could be construed as an expansion of the standard; therefore, the drafting team deleted "or not" based on a comment.

Guidelines and Technical Basis

The drafting team made grammatical corrections to text in the Rationale boxes associated with several Requirements. Rationale boxes will be moved to the end of the Guidelines upon adoption. The drafting team added a number of examples requested throughout comments. Also, the drafting team reconsidered the lowercase use of the term "fault" throughout the Guidelines and Technical Basis. The team changed a number of instances back to the *Glossary of Terms Used in NERC Reliability Standards* capitalized term "Fault" for increased clarity. The use of the term throughout the Guidelines and Technical Basis does not change any meanings and is only intended to provide the reader a more specific understanding of the guidance. Some instances were not changed because they are lowercase (e.g., use of "fault" in the current definition of "Misoperation").

Due to continued questions about the time periods in each of the Requirements, the drafting team consolidated text about time periods into its own section, "Requirement Time Periods." This section explains what other sections already addressed in one concise location for all Requirements. Last, minor corrections were made to the flowchart text to more closely align with the text in the Requirements based on a comment.

Implementation Plan

The drafting team corrected the Implementation Plan to align the definition of "Misoperation," category 2 and Applicability section concerning Facilities with the draft PRC-004-3 Reliability Standard. These revisions occurred in the previous posting and were not aligned with the text presented in the draft 5 of the PRC-004-3 Reliability Standard.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Québec TransÉnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

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

12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	Next Era Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Québec TransÉnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
22.	Peter Yost	Consolidated Edison Co, of New York, Inc.	NPCC	3
23.	Brian Robinson	Utility Services	NPCC	8

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

N/A

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Michael Jones	National Grid	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Shanahan	National Grid		3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5
4.	Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Fink	Entergy		
2.	Paul Nauert	Ameren		
3.	Bridget Coffman	Santee Cooper		
4.	Steve Edwards	Dominion		
5.	Jerry Blackley	Duke Energy Progress		
6.	David Greene	SERC		

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis, LLC	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
12.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brian Hobbs	Western Farmers Electric Cooperative	SPP	1, 5
2.	Lucia Beal	Southern Maryland Electric Cooperative	RFC	3
3.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
4.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
7.	John Shaver	Southwest Transmission Cooperative	WECC	1
8.	Bob Solomon	Hoosier Energy	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Carol Chinn	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utilty Service	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3
10.	Richard Bachmeier	Gainesville Regional Utilties	FRCC	1
11.	Mike Blough	Kissimmee Utility Authority		5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Robert Rhodes	SPP Standards Review Group		X								

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Border	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA
2.	Paul Von Herstenberg	Westar Energy	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Shannon Mickens	Southwest Power Pool	SPP	2
8.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
9.	Steve Shipps	Westar Energy	SPP	1, 3, 5, 6
10.	Sean Simpson	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA
11.	Sam Snedaker	American Electric Power	SPP	1, 3, 4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	System Control Engineering	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Dianne Gordon	Operational Compliance	X		X		X					
N/A													
17.	Individual	David Jendras	Ameren	X		X		X	X				
18.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
19.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
20.	Individual	David Thorne	Pepco Holdings Inc	X		X							
21.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
22.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
23.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
24.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
25.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Oliver Burke	Entergy Services, Inc.	X									
27.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
28.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
29.	Individual	Roger Dufresne	Hydro-Québec					X					
30.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
31.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
32.	Individual	Jonathan Meyer	Idaho Power	X									
33.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
34.	Individual	Leonard Kula	Independent Electricity System Operator		X								
35.	Individual	Gul Khan	Oncor Electric Delivery LLC	X									
36.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
37.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
38.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
39.	Individual	Karin Schweitzer	Texas Reliability Entity										X
40.	Individual	Bill Temple	Northeast Utilities	X									
41.	Individual	John Brockhan	CenterPoint Energy	X									
42.	Individual	Don Cuevas	Beaches Energy Services	X									
43.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
44.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
45.	Individual	Venona Greaff	Occidental Chemical Corporation							X			
46.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
47.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates the entities below supporting the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the drafting team in responding to comments. This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of "Entity Name"
Ameren	Agree	Ameren supports and adopts by reference the SERC PCS comments.
Beaches Energy Services	Agree	FMPA - Florida Municipal Power Agency
Occidental Chemical Corporation	Agree	Ingleside Cogeneration LP

1. Based on stakeholder input, the drafting team revised the proposed definition of "Misoperation." Concerning the two categories of "Slow Trip." The drafting team also clarified the proposed definition of "Composite Protection System." Do you agree the revisions provided clarity? If not, please provide specific suggestions for improvement

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 60 percent of individual stakeholders that commented in support of the drafting team's revised the proposed definition of "Misoperation," the two categories of "Slow Trip," and clarifications to the proposed definition of "Composite Protection System." There were 12 comments by 49 individuals that were not supportive of the revisions and there were 29 entities represented by 80 individuals that did not comment and only provided a "yes" response to the question in support of the drafting team's revisions.

There was one common issue raised in this section that resulted in a clarifying revision to the proposed definition of "Composite Protection System." Six comments by 34 individuals requested the drafting team to clarify the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. To clarify, the drafting team changed the last sentence from an "inclusionary" statement to an "exclusionary" statement. The phrase "[b]ackup protection provided to a remote Protection System is included" was clarified to "[b]ackup protection provided by a different Element's Protection System(s) is excluded."

There were three common issues that were raised by commenters that did not result in revisions. Three comments by 18 individuals requested changes to the definitions of "Composite Protection System" and "Misoperation." Another three comments by individuals noted a lack of clarity on the differences in either the categories of the definition of "Misoperation," the cited examples in the Guidelines, and/or the case where backup protection was provided for a failed Protection System of another owner. Two comments note that the definition of "Composite Protection System" is unnecessary and should not include, for example, redundant systems because in their opinion any failure in the Protection System should be identified as a Misoperation. The drafting team concluded that the suggested changes did not provide additional clarity.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	In the Composite Protection System definition “Backup protection provided to a remote Protection System is included.” is not clear because it directs the focus from the local protected Element to a remote protection system. Suggest revising this sentence to read “Backup protection provided by a remote protection system by design is included.” **Response:** The drafting team clarified the intent of the definition of “Composite Protection System” to eliminate the confusion of whether “remote” was local or away from the initiating Protection System. The phrase “a remote Protection System” was clarified to “a different Element’s Protection System.” Change made.
National Grid	No	Definitions for “Failure to Trip - During Fault” and “Failure to Trip - Other Than Fault” state that “The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct”. However, requirement R1 asks to identify if “Protection System component(s) caused a Misoperation”. These statements seem to contradict each other. **Response:** The drafting team asserts that every Protection System Misoperation will include the failure of a component to act properly for an identified Misoperation. If the Composite Protection System operates as intended, it is not a Misoperation. No change made. Definition for “Unnecessary Trip - Other Than Fault” provides examples for what it is not. It should also provide examples for what it is, similarly with other definitions. **Response:** The current draft includes what “is a Misoperation” (Examples 6a-6d) and what “is not a Misoperation” (Example 6e). No change made.

Organization	Yes or No	Question 1 Comment
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. It is helpful that the Definitions section on p.3 of the standard now says that a Slow Trip classification applies only if the Protection System of another Element was made to operate, but the term "slower than required" should be revised for clarity to read, "slower than the setting specified in the test/calibration instructions." That is, a Slow Trip should be declared only if the timer is found to be mis-adjusted. Otherwise there's no way of knowing whether the device at fault was slow or simply failed to function. Uncertainty on this subject is increased by Example 4 on p.25 having been left in its previous (draft 3) wording, "A failure of a generator's Composite Protection System to operate as quickly as intended for an overexcitation condition is a Misoperation." This puts us back in the situation of having to decide if a relay acted in, say, ten cycles when five cycles was intended. Having to make such determinations ranges from being unduly burdensome to (for electromechanical relays) impossible, and was the principal reason for our having voted against draft 3 of the standard. It would be better still to state that Slow Trips apply only for TOs, because the issues of concern for this category of Misoperation (e.g. system instability, sequence of tripping) do not apply for generation plants. The description on p.25 of the standard of, "...owner(s) reviewing each Protection System operation," to determine whether or not, "the speed and

Organization	Yes or No	Question 1 Comment
		outcome...met their objective," is not typical or appropriate for GOs, and they should not be required to add monitoring systems and design-level personnel to perform a no-value-added function. **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. It is appropriate to include Generator Owners in the standard's Applicability. No change made.
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	No	The composite protection definition involving backup to remote protection does not completely make sense when coupled with the "slow trip" definition. The "total compliment" description in the Composite Protection System definition indicates that remote backup protection is included in the "total compliment". If the remote backup protection operates instead of the local, primary protection for an element, the "total compliment" collectively functioned to protect the element. Calling this situation a "misoperation of the Composite Protection System" is contradictory to stating that the total compliment collectively functioned as intended. Also, how does this make sense for the protection systems at generating facilities? What does 'backup protection provided by a remote protection system' mean for generating facilities? **Response:** The definition of "Composite Protection System," has been clarified to address the intent of backup protection. Clarification made. The slow trip definitions are still confusing. Are there multiple Composite Protection Systems that need to be considered when determining if a trip is a slow trip?

Organization	Yes or No	Question 1 Comment
		The "its operating time" references are indefinite in the definition. Consider making the slow trip definition either one of the following or a combination of the following OR statements: "a composite protection system operation that is slower than required or slower than designed or slower than desired or slower than the intended design". **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. No change made. There is a fundamental flaw in the definition of misoperation. A misoperation is recognizable any time any part of a protection system design fails to operate as intended by the design, regardless of the existence of a redundant, remote, or back up protection scheme. The fact that something did not operate properly should indicate that a misoperation has occurred. The addition of the adjective "reportable" simply classifies the types of misoperations that are to be reported. The comment above does not address a requirement governing the actual reporting. **Response:** The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This new definition has been introduced in this draft PRC-004-3 Reliability Standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation. No change made.

Organization	Yes or No	Question 1 Comment
Operational Compliance	No	A. The Application Guidelines provide some clarity on the difference between "Slow Trip - During Fault" and "Unnnecessary Trip - During Fault". However, these definitions may still not be entirely clear. **Response:** The drafting team asserts that the Guidelines and Technical Basis is the appropriate place for clarification rather than the definition of “Misoperation.” No change made. B. Quoting Requirement R1...p.31 of Application Guidelines "When Elements are isolated from the BES and undergoing maintenance.....not subject to the standard....provided they do not result in the operation of...part of the BES." This statement and Example 6e (#6 of Misoperation definition), p.28 (at first glance anyways) may be at odds. **Response:** The text referenced on page 31 has been removed because maintenance cannot change the applicability of the standard. Example 6e is not a Misoperation of an in-service Element because of the maintenance exclusion; however, the owner of the BES interrupting device that operates will review the operation when the operation meets the circumstances in Requirement R1, Parts 1.1 through 1.3. Clarification made.
Wisconsin Electric Power Company	No	The 2nd sentence in the definition of Composite Protection System is “Backup protection provided to a remote Protection System is included.” The meaning and intention of this phrase is not readily understood. We suggest that the phrase from previous Draft 4: “Backup protection provided by a remote Protection System is excluded”, is clearer and should be re-instated. **Response:** The definition of “Composite Protection System,” has been clarified to address the intent of backup protection by providing an

Organization	Yes or No	Question 1 Comment
		"exclusionary" condition rather than an "inclusionary" condition. Clarification made.
Public Service Enterprise Group	No	We agree with the Slow Trip changes. However, the revised definition of Composite Protection System caused much discussion. In the end, we would accept it provided that "a remote" in the second sentence is changed to "another." With this change, the second sentence would read "Backup protection provided to another Protection System is included." The backup Protection System need not be "remote" physically; it could be located in the same substation. The phrase "a remote Protection System" would require that the backup Protection System be at a different physical location, which may not be the case as we have just described. **Response:** The drafting team clarified the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. The phrase "a remote Protection System" was clarified to "a different Element's Protection System." Clarification made.
Independent Electricity System Operator	No	We generally agree with the changes to the proposed definition of Misoperation, but do not agree with the proposed addition of the term Composite Protection System. In our previous comments, we expressed our disagreement with the need to create a defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is therefore redundant. In the comment report, the SDT's response indicates that the reason for proposing the newly defined term, "Composite Protection

Organization	Yes or No	Question 1 Comment
		System," is found in the Application Guidelines under the heading "Definitions.", and therefore no change was made. In the Application Guideline, the rationale provided for introducing this new term is that: [The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.]We find this rationale insufficient to justify the introduction of the new term since by having the defined term "Misoperation" which covers any failure a Protection System to operate as intended for protection purposes would suffice to include the effect of multiple levels of protection (e.g. redundant systems). In other words, if a Protection System failed to operate as intended or operated unnecessarily, then regardless of the level of protection and which component caused the Protection System to operate, the action/inaction of the Protection System - Composite or otherwise, would constitute a Misoperation. We therefore continue to disagree with the proposed addition of this new term, and suggest that it be removed. **Response:** Not all entities consider a Protection System to include all associated components to protect an Element. The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This new definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation. Also, the new definition supports consistent

Organization	Yes or No	Question 1 Comment
		reporting of Misoperations under the Section 1600 data request because all entities, under the new definition, will be evaluating its Composite Protection Systems in the same manner. No change made.
Southern California Edison Company	No	SCE disagrees with the explanation of and rationale for the "Composite Protection System" for the following reasons: 1. If an interrupting device is tripped due to misoperation of another device not owned by the owner of the interrupting device, then the owner of the interrupting device will be unaware of this issue until the formal notification of the event to all the owners of the composite protection system is made. One of the reasons for the misoperation of the other device could be a failure to trip. **Response:** The drafting team contends that this concern is addressed by Requirement R2. The new definition of "Composite Protection System," has been clarified to address the intent of backup protection. Clarification made. 2. In the case above, the owner of the interrupting device would not be able to validate Requirement 1.3: "The BES interrupting device owner identified that its Protection System Component caused the BES interrupting device(s) operation." Therefore the owner would not be able to and may not be required to notify other entities owning the composite protection system. The root cause would either not be analyzed or the analysis would be delayed. **Response:** Requirement R1 is for the BES interrupting device owner to initiate the review for identifying any Misoperations caused by its components. Requirement R2 addresses the circumstances in which the initiating BES interrupting device owner in Requirement R1 must make

Organization	Yes or No	Question 1 Comment
		notification to other owners. The notified Protection System component owner(s) in R3 must review its portion of the Composite Protection System for any Misoperation. No change made.
Northeast Utilities	No	The part of the Composite Protection System definition "Backup protection provided to a remote protection is included" is not clear because it switches focus from the local protected element to a remote protection system. We suggest revising this part to say "Backup protection of the element provided by a remote protection by design is included." **Response:** The drafting team clarified the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. The phrase "a remote Protection System" was clarified to "a different Element's Protection System." Clarification made.
CenterPoint Energy	No	CenterPoint Energy recommends adding wording to the definition to address the direct interrelationships between Misoperation categories, especially the "Slow Trip - During Fault" and the "Unnecessary Trip - During Fault" categories. For these two categories, an operation of an un-faulted Element's Composite Protection System occurs. This interrelationship is detailed in the Application Guidelines which states the following for the "Slow Trip - During Fault" category: "In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip - During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element. If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip - During Fault" category of Misoperation at the local terminal." In addition, the Application Guidelines states the following for the Unnecessary Trip - During

Organization	Yes or No	Question 1 Comment
		Fault: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip - During Fault” category of Misoperation at the remote terminal.” CenterPoint Energy suggests adding clarifying wording at the end of the “Slow Trip - During Fault” and the “Unnecessary Trip - During Fault” categories: 3. Slow Trip - During Fault - A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System, providing it is not determined to be an Unnecessary Trip - During Fault. 5. Unnecessary Trip - During Fault - An unnecessary Composite Protection System operation for a Fault condition on another Element, providing it is not determined to be a Slow Trip - During Fault. **Response:** The drafting team asserts that the Guidelines and Technical Basis is the appropriate place for additional explanation rather than within the definition of “Misoperation.” No change made.
Flathead Electric Cooperative, Inc.	No	Generally do not like the phrase "composite", would prefer that Protection System just have a solid definition. I appreciate that is the dilemma here and my specific suggestion be to delete the word composite throughout. **Response:** The drafting team contends that modifying the Protection System definition in the *Glossary of Terms Used in NERC Reliability Standards* impacts all Reliability Standards using the term. No change made.
JEA	Yes	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	
ACES Standards Collaborators	Yes	We agree with the changes. **Response:** Thank you for your comment.
Florida Municipal Power Agency	Yes	FMPA's primary concern with the previous version of this definition centered around the ability to accurately classify the events and show evidence as appropriate. FMPA agrees the revised versions of "Slow Trip - During Fault" and "Slow Trip - Other than Fault" are more specific and thus easier to consistently apply. However, we do not believe the revised versions are going to result in events being classified the way the SDT desires. We are voting yes for this item because our primary concern is addressed. The SDT should reconsider these revisions, though, in light of the following - the revised versions have nothing to do with the designed, set, or normal operating time as specified by the relay manufacturer/settings. We believe the intent of these two categorizations is to identify relay misoperations for which a relay, interrupting device, or relay setting which was intended to operate at a particular speed, instead operated at a slower speed / in a

Organization	Yes or No	Question 1 Comment
		longer time. Just because a relay from a different Element's Composite Protection System operates does not necessarily mean this event was undesired, unnecessary, or unintended. As stated in our last comments we refer back to the core issue that the protection system performance should be measured against a company's relay setting philosophy. We also note that the Application Guide still refers to this event in "Example 3" as "A failure of a line's Composite Protection System to operate as quickly as intended...". **Response:** The modifications to the category of "Slow Trip" were previously made to simplify the identification and improve the measurability. The identification is based on the reliability impact. Example 3 in the Guidelines and Technical Basis have been clarified to remove the "quickly" wording. The drafting team contends that design philosophies inherently include the principles of dependability and security. Each entity using its particular design philosophy would lead to less consistent classification of Misoperations. No change made. The application guide also still includes language regarding "slower than previously identified as being necessary to prevent voltage or dynamic instability". **Response:** The Guidelines and Technical Basis have been updated to remove this reference. Correction made.
SPP Standards Review Group	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	The most recent draft of the proposed standard added a definition for a composite protection system which satisfies our previous concerns. **Response:** Thank you for your comment.
American Electric Power	Yes	
Xcel Energy	Yes	
Entergy Services, Inc.	Yes	
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Hydro-Québec	Yes	
Nebraska Public Power District	Yes	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration ("ICLP") agrees that the drafting team has made a change for the better in the definition of "Misoperation". The prior version would perhaps lead to more technically-accurate identifications of slow-trip incidents, but made too many assumptions around our capability as a GO to conduct a performance evaluation of the Composite Protection System. We simply do not have the tools or training to determine if high-speed

Organization	Yes or No	Question 1 Comment
		performance is necessary to prevent voltage or dynamic instability. In fact, we may not be aware that a slow trip took place if a secondary or back-up Protection System acts in a manner that masks the condition. We believe that improper operation of a nearby Protection System may be an indication that a slow trip occurred. From that point on, an investigation can ensue that has a chance of success - as our investigative capabilities are designed to address such events. In addition, the bright-line definition leaves no room for a violation assessment based upon a CEA's interpretation that the GO should have deployed sophisticated recorders (DME) or situational analysis tools to prepare for a Misoperation of the type. **Response:** Thank you for your comment.
Idaho Power	Yes	
Oncor Electric Delivery LLC	Yes	
Omaha Public Power District	Yes	
Cleco	Yes	
Texas Reliability Entity	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Electric Reliability Council of Texas, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
Wolverine Power Supply Cooperative, Inc.	Yes	

2. Based on stakeholder input, the drafting team revised Requirement R2 to clarify responsibilities when local protection is responsible for the interrupting device operation and when backup protection is responsible. This also addresses the notifications that must occur to eliminate a gap in the previous draft. The gap was a condition where an entity's BES interrupting device did not operate because of a failed Protection System; therefore, would not have been applicable to the standard. Do you agree that the gap has been eliminated with the change to Requirement R2? If not, please provide specific suggestions for improvement.

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 62 percent of individual stakeholders agreed with the approach used by the drafting team in Requirement R2 to clarify responsibilities when local protection is responsible for the interrupting device operation and when backup protection is responsible. This also addresses the notifications that must occur to eliminate a gap in the previous draft 5.

There were two common comment themes that required a clarification in the standard. First, a single comment by 23 individuals raised concern that the drafting team failed to make it obvious that an entity should also have to notify other owner(s) of Protection Systems under the same circumstances in Requirement R1 for a BES interrupting device operation by manual intervention in response to a Protection System failure. The drafting team agreed with the lack of clarity and inserted the appropriate phrase to highlight that this circumstance is intended to be covered by Requirement R2. Second, two comments by individuals disagreed with the way Requirement R2, Part 2.2 was constructed when compared with the definition of "Composite Protection System." The drafting team did not make a change to Part 2.2 based on the comment, but provided additional explanation in the response how the clarification to the definition of "Composite Protection System" should address the concern.

There were six varying comment themes that did not require the drafting team to clarify the standard. Of those, two comments by nine individuals believed that requirements for providing notifications overly complicate the standard. The drafting team contends that requiring notifications is important to ensuring all Protection System owners become aware of when they need to review their Protection Systems, and when notified, that they have a responsibility to perform the necessary requirements. A single comment expressed concerned about the entity that provided remote backup protection having to track operations. The drafting team noted that a BES interrupting device operation meeting the circumstances in Requirement R1 dictate that a review of the operation be performed. Requirement R2, Part 2.2 requires that entity to notify the other owner(s) for which backup protection was provided. Two comments by 12 individuals were concerned that 120 calendar days is too long of a period and would not promote effective and efficient resolution of the problem. The drafting team contends that most Protection System reviews would occur soon after a

BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load.

The last three comments were provided by an individual commenter. One comment raised concern that Measure M2 limited an entity's ways to demonstrate coordination of evidence. The drafting team contended that Measure M2 specifically notes that evidence "may include, but is not limited to." A second comment disagreed that the BES interrupting device owner should be responsible for demonstrating compliance with the requirements in the proposed standard. The drafting team contends that the trip coil(s) of a BES interrupting device are, by definition, included in what is considered a Protection System. Last, one comment pointed out that the entity did not see how the gap regarding a case where an interrupting device did not operate has been addressed. The drafting team is confident that a BES interrupting device will operate, somewhere in the system to clear the abnormal condition, thus the entity that owns the BES interrupting device that clears the abnormal condition will notify the other owner(s).

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The case where manual intervention is required to open a BES interrupting device, but the cause of the Misoperation is located on a Protection System component owned by another Transmission Owner is not addressed in R2. In R1 a special mention to manual intervention is included. Why isn't a process of notification included in R2 for manual intervention caused by Misoperation of another owner's protection system? **Response:** The drafting team intended in Requirement R2 that a BES interrupting device operation due to a Protection System operation or by manual intervention in response to a Protection System failure would be considered in whether or not notifications to other owners would be required. The drafting team added the appropriate clarification for "by manual intervention in response to a Protection System failure to operate." Clarification made.
Southern Company: Southern Company Services, Inc.;	No	There is a problem with R2.2. One entity does not necessarily know whether or not another entities' Element has an abnormal condition. This notification of other entities

Organization	Yes or No	Question 2 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		for an explained operation of my interrupting device and my protection system should not be required. It is acknowledged that this was an attempt to eliminate the gap described above, but it is contrary to the Composite Protection System collectively functioning as intended to protect an element. **Response:** Requirement R2 provides the circumstances where the initiating entity either determines that the operation was not caused by its Composite Protection System components or the initiating entity is unable to rule out a Misoperation. The drafting team contends that the initiating entity will be in the position to determine its Protection System operated correctly. If not, Requirement R2 requires notification to other owners if the initiating entity is unable to rule out a Misoperation. No change made. Also, the drafting team clarified the intent of the definition of "Composite Protection System" to eliminate the confusion of whether "remote" was local or away from the initiating Protection System. The phrase "a remote Protection System" was clarified to "a different Element's Protection System." Clarification made.
ACES Standards Collaborators	No	(1) We continue to believe that this standard has been overly complicated by including administrative elements such as reporting information to third parties. The reporting does little to nothing to support reliability. The real value is in analyzing the Protection System operations and correcting any errors. Is there any indication that registered entities are not communicating to co-owners of the Composite Protection System that a potential misoperation occurred? If not, (and we have seen no such evidence) why does this administrative requirement that clearly meets multiple P81 criteria (administrative and reporting) rise to level of needing to be enforced with financial penalties? Barring such evidence, we simply do not see how we can support such a requirement. Clearly, the application guidelines spell out what is necessary. We recommend that the drafting team perform a study to determine if there is a true

Organization	Yes or No	Question 2 Comment
		reliability need for communicating with co-owners of Composite Protection Systems. If the drafting team cannot provide data or statistics indicating a gap in reliability, then we recommend striking the administrative tasks from the requirement. **Response:** Requirement R2 requires notification to other owners of the Composite Protection System who have a reliability role in identifying Misoperations, but were not accounted for within Requirement R1. Requirement R2, under the circumstances in Part 2.1 and Part 2.2 determine when the notification to other owners must occur. No change made. (2) The existing standard was fairly simple and coupled with the new definition of Misoperation largely addresses the scope of the SAR. All that is really is needed for this standard is a requirement to evaluate Protection System operations, identify if the Protection System operation was a misoperation and then to develop a Corrective Action Plan to prevent future misoperations. Six requirements create more complication than what is necessary. **Response:** The Requirements provide additional clarity over the current version two PRC-004-2.1a Reliability Standard that has three activities in a Requirement. This draft version three PRC-004-3 Reliability Standard has one reliability activity per Requirement and those Requirements provide the essential actions to ensure each and all entities are informed. No change made.
Seminole Electric Cooperative, Inc.	No	Requirements R1 and R2 place the burden on the owner of a BES interrupting device to initiating a review on the operation of the device. This responsibility should fall on the owner of the components of the Composite Protection System that initiated the BES interrupting device to operate. The owner of these components should be just as aware as the owner of the device regarding its operation. In addition, for those entities that are interconnected and who utilize the same BES interrupting device, those entities should have equal awareness of the BES interrupting device status.

Organization	Yes or No	Question 2 Comment
		Therefore, Seminole recommends that the SDT revise Requirements R1 and R2 to require the entity whose components of the Composite Protection System initiated the BES interrupting device to activate. **Response:** According to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). The BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. In the case where the relays or other Protection System component(s) are owned by another entity, that owner may not know of the operation until it receives notification from the BES interrupting device owner. No change made.
Nebraska Public Power District	No	R2 2.2 states: "For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided." Perhaps it would be clearer to state: "For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Element, notification of the operation shall be provided to the other Protection System owner(s) from the backup protection system owner(s) for which that backup protection was provided." **Response:** The drafting team disagrees that the suggestion provides additional clarity. No change made.

Organization	Yes or No	Question 2 Comment
		A concern with the gap fix is that the backup protection system owner will not be tracking this as a misoperation because the owner of the interrupting device is the one who had the misoperation yet the backup protection owner must store this notification as part of a misoperation on another entities system which creates an odd and risky compliance tracking situation. It would be unfortunate to get fined for not tracking this even though a misoperation did not occur on your system. This is a difficult situation to address. **Response:** Regardless of fixing the gap (i.e., R2, Part 2.2), the entity that experienced a BES interrupting device operation is required to review the operation according to the circumstances in Requirement R1. For example, if the operation was "correct" it would not be identified as a "Misoperation;" however, Requirement R2, Part 2.2 requires that the entity provide notification to the other Protection System owner(s) if the operation was a result of providing backup protection for a condition on another entity's Element. No change made. For a backup protection system owner who operates in back up for a fault on a non BES or non-registered entities system is the notification not required? **Response:** Requirement R2, Part 2.2 has been clarified that the "other entity's Element" is a "BES Element." The Guidelines and Technical Basis have been supplemented for this condition. Clarification made.
Idaho Power	No	Protection Systems regularly provide backup to the next Element. These backup features are not intended to operate under normal conditions and would not be included as part of an Element's Composite Protection System as we interpret it. The phrase "intended to operate" in 2.2 should be modified to account for operations of another Element's Composite Protection System that could operate as backup to the normal Composite Protection System for an extreme event.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team clarified the definition of "Composite Protection System." Back up protection provided by a different Element's Protection System(s) is excluded. The intent of Requirement R2, Part 2.2 is for the condition where an entity provides backup protection for a different Element's Protection System, such as, the case of a failed protection system of another BES Element. Part 2.2 requires that the entity that provided the backup protection (i.e., a correct operation) is required to notify the other Protection System owners to close the reliability gap for a BES interrupting device that did not operate. A clarification was made to the definition of "Composite Protection System."
Southern California Edison Company	No	In the case where a non-performing protection system has caused a tripping device to operate, the non-tripping device could be ignored, resulting in the problem not being mitigated and eventually posing a greater risk to the composite protection system. Assuming that the owner of the system notifies the other entities owning the composite protection system, the time window of 120 days to notify would be too long in order to promote effective and efficient resolution of the problem. Notification should be within a week of the occurrence of event in order to allow the other impacted entities to review, analyze, and communicate with each other in order to perform a root cause analysis and determine a corrective action plan. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load. Also, requiring automatic notifications to other owners of the Composite Protection System would create an unnecessary compliance burden on entities (i.e., Requirement R3) if the initiating entity did not perform a cursory review of the Protection System operation first. No change made.

Organization	Yes or No	Question 2 Comment
		Requirement R2 provides the circumstances where the initiating entity either determines that the operation was not caused by its Composite Protection System components or the initiating entity is unable to rule out a Misoperation. No change made.
Tri-State Generation and Transmission Association, Inc.	No	Tri-State remains concerned with situations where individual components are jointly owned. The SDT's response "While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results" appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated "Compliance Entity". Typically compliance contracts take some time to come to fruition. Is it the drafting team's intent that misoperations be reported by multiple entities in this situation until a contract is finalized? **Response:** The reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., "data request"). Absent an agreement, all owners of a Protection System will have a compliance responsibility. No change made.
Flathead Electric Cooperative, Inc.	No	The way the M2 is written is overly prescriptive and limiting on what might be acceptable way to show the coordination between entities. The measure seems to written like a requirements. Prefer the previous language.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes the Measure is worded "may include, but is not limited to," thus allowing other forms of evidence. The wording of the Measure follows NERC guidance. No change made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
National Grid	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	
SPP Standards Review Group	Yes	Formatting in recent standards has tended toward using bullets in lieu of subparts. The drafting team is encouraged to follow this practice in Requirement R2. Note that there are bullets in Requirement R5. **Response:** The drafting team followed the NERC convention for numbering and bulleting. Numbered items mean "and" which requires all of the items to be considered or performed. Bullets mean "or" and generally mean one or more are required depending on the Requirement text. No change made.

Organization	Yes or No	Question 2 Comment
		Delete the 2nd ‘when’ in the 6th line (clean copy) of the Rationale Box for Requirement R2. **Response:** The drafting team removed the second occurrence of “when.” Change made.
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	We are in agreement that this revision eliminates the identified gap. However, we are still not in agreement that the owner of the interrupting device be responsible for demonstrating compliance with the requirements in the proposed standard, as has been previously stated. This is of particular interest at interface terminals with generator owners. **Response:** The drafting team thanks you for your comment. The drafting team contends that the BES interrupting device owner is in the best position to be aware of the operation and to initiate the identification of any Misoperation. No change made.
American Electric Power	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 2 Comment
Wisconsin Electric Power Company	Yes	
Public Service Enterprise Group	Yes	
Entergy Services, Inc.	Yes	
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Hydro-Québec	Yes	
Ingleside Cogeneration LP	Yes	ICLP agrees that there are situations where a relay owned by an external entity may trip a circuit breaker protecting an Element owned by another entity. The interrupting device and relay owners will need to coordinate their investigations in order to resolve the issue - and R2 now ensures that the process will be initiated. **Response:** The drafting team thanks you for your comment.
Tacoma Power	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery LLC	Yes	

Organization	Yes or No	Question 2 Comment
Omaha Public Power District	Yes	
Cleco	Yes	
Northeast Utilities	Yes	
Electric Reliability Council of Texas, Inc.	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Florida Municipal Power Agency		1. FMPA does not feel our previous comment regarding notification to affected entities was properly understood. This comment was offered to R2 in the previous round of comments. We understand the way the document is intended to flow, but our main concern is the relay event records are preserved by all entities indefinitely - for many Utilities a special trip must be made to the substation to download the event records. What prevents the Owner of a BES interrupting device that operated from taking the full 120 days to conduct their review without saying anything to the other affected owners, only to find upon request of further evaluation that those entities no longer have the relay event records necessary for the evaluation? At minimum the entity Owning the BES interrupting device should advise the other affected Protection System owners that the investigation is under way at the earliest time they determine those entities are affected, to allow the entities to be prepared with data should they be notified in accord with R2. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work

Organization	Yes or No	Question 2 Comment
		load. Also, requiring automatic notifications to other owners of the Composite Protection System would create an unnecessary compliance burden on entities (i.e., Requirement R3) if the initiating entity did not perform a cursory review of the Protection System operation first. No change made. FMPA does not see how the gap regarding a case where an interrupting device did not operate has been addressed. Reading R1 and R2 again, it still appears that all triggers for activity are based on interrupting device operation, and we see no mention of a case where an interrupting device did not operate. While we can see that requiring actions in the standard based on relay targets, for example, would be challenging to enforce, we would have expected at least a statement, something to the effect of "Or if the entity otherwise becomes aware that a Composite Protection System it owns operated without an associated interrupting device action". **Response:** The drafting team is confident that a BES interrupting device will operate, somewhere in the system to clear the abnormal condition. The draft PRC-004-3 Reliability Standard is initiated on the operation of a BES interrupting device. Requirement R2 addresses this perceived gap for a device not operating because an entity that provided backup protection is required to notify the entity for which it provided backup protection. The other entity is then required under Requirement R3 to review its Protection System for Misoperation. No change made.
Texas Reliability Entity		No comments
CenterPoint Energy		CenterPoint Energy recommends deleting the proposed Requirement R2.2. Based upon the changes made to the Composite Protection System definition and the proposed wording of Requirement R2.1, CenterPoint Energy believes the proposed wording of Requirement R2.2 related to backup protection is unnecessary. The Composite Protection System definition now states that "Backup protection provided

Organization	Yes or No	Question 2 Comment
		to a remote Protection System is included.” This, along with Requirement R2.1 stating “notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances” and Requirement R2.1.2 stating “The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation”, provides for the notification intended by Requirement R2.2. **Response:** The drafting team clarified the definition of “Composite Protection System.” Back up protection provided by a different Element’s Protection System(s) is excluded. The intent of Requirement R2, Part 2.2 is for the condition where an entity provides backup protection for a different Element’s Protection System, such as, the case of a failed protection system of another Element. Part 2.2 requires that the entity that provided the backup protection (i.e., a correct operation) is required to notify the other Protection System owners to close the reliability gap for a BES interrupting device that did not operate. A clarification was made to the definition of “Composite Protection System.”

3. The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). More than 70 percent of individual stakeholders agreed that the Guidelines and Technical Basis was improved by the numerous examples and that it clarified the team's intent on various topics.

There were three themes in the comments that resulted in revisions to the standard's Guidelines. Five comments by 16 individuals requested additional examples in the Guidelines. Among the requests, examples included breaker failure, "Failure to Trip – During Fault," "Slow Trip – During Fault," "Slow Trip – Other Than Fault," "Unnecessary Trip – During Fault," and Requirements R1 and R2. The drafting team supplemented the Guidelines with most of the examples suggested by stakeholders. Four comments by 14 individuals suggested minor word clarifications, punctuation improvements, and grammar corrections needed in the Guidelines. The drafting team concurred with many of the suggestions and implemented the clarifications, improvements, and corrections. A single comment by 11 individuals noted minor issues with wording in the Guidelines that was not updated during previous revisions of the definitions. The drafting team addressed these issues.

The following five comments did not result in revisions or clarifications in the draft PRC-004-3 Reliability Standard or related documents. First, four comments by 21 individuals remained concerned with the "Slow Trip" category of the Misoperation definition. The drafting team noted that it may take a detailed investigation to distinguish between a "Slow Trip" and "Failure to Trip" category of Misoperation. However, making a distinction is not relevant to the Requirements because the entity is required to identify whether a Misoperation of its Protection System components occurred. Second, one comment by 11 individuals expressed concern that an entity does not have any flexibility in the timeframes of the Requirements for extenuating circumstances if the entity did not meet the timeframes due to an event such as a natural disaster. The drafting team responded that NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (i.e., "timeframes") of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances allow the Compliance Enforcement Authority this flexibility based on the entity's unique circumstances. Third, a single commenter believed that Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES) should be first identified by the Planning Coordinator or Reliability Coordinator. The drafting team noted that the current version of the draft Reliability Standard (PRC-004-2.1a) applies to all BES Protection Systems; therefore, the Planning Coordinator or Reliability Coordinator do not need to identify specific BES Elements that affect reliability, only the owners of Protection Systems. Fourth, an individual commenter suggested adding a Requirement to require the BES interrupting device owner to share any information it has regarding the operation of the Composite Protection System. The drafting team finds such a requirement to be administrative and a compliance burden when information is already being communicated. Last, a single commenter questioned about how the timeframes relate between the Requirements. The drafting team appended a new section, “Requirement Time Periods” to the Guidelines to provide clarity regarding timeframes.

Organization	Yes or No	Question 3 Comment
PPL NERC Registered Affiliates	No	See our comments above for Example #4. The Application Guidelines should clarify Misoperation analysis scope and purpose differences between TOs (preserve stability and enforce orderly isolation of circuits on a still-live system) and GOs (trip the unit). **The following text was provided to the drafting team by the group’s submitter after the drafting team requested clarification to the above comment:** *The following response was developed by a PPL SME. Please contact me if you have additional questions.* *The issue has to do with our objections regarding slow trips. Previous versions of the standard could be interpreted as requiring us to identify the time delay associated with every relay action, to see if the device functioned as quickly as intended. We (and probably most GOs) don’t have equipment allowing such a determination. The SDT sought to address this concern by revising the definitions to state that a slow trip occurs only if another, backup relay was made to operate.* *Two shortcomings remain, however. One doesn’t know whether the primary device that didn’t get the job done was slow or it was utterly non-functional. The classification of a slow trip should then apply only if the timer was found to be mis-programmed.*

Organization	Yes or No	Question 3 Comment
		Response: Since the symptoms are similar, it may take a detailed investigation to distinguish between a "Slow Trip" and "Failure to Trip" category of Misoperation. However, this is not relevant to the Requirements. The entity is required to identify, within 120 days, whether a Misoperation occurred. The definition's wording change simplifies the identification process by allowing entities to use an operational evaluation to identify whether a Misoperation occurred. In the cited example, it should become clear during subsequent investigation whether a "Slow Trip" or "Failure to Trip" type Misoperation occurred. No change made. Secondly, the SDT forgot to revise the wording for Example 4 on p.25 of the Application Guidelines. It still talks about, "A failure of a generator's Composite Protection System to operate as quickly as intended," contradicting the revised definition. **Response:** Example 4 has been updated.
SPP Standards Review Group	No	We note that the drafting team included several additional examples in this version of the standard and we certainly appreciate that. We would however suggest that the following examples would provide further clarification: 1) an example which illustrates that a properly coordinated breaker failure operation does not equate to a slow-trip operation, **Response:** The drafting team has provided an example in the Guidelines and Technical Basis under "Composite Protection System – Breaker Failure Example" section, second bullet. Clarification made. 2) a backup protection example to provide clarity on how Requirement 2, Part 2.2 would be applied and

Organization	Yes or No	Question 3 Comment
		Response: The drafting team has provided Example 1e in the Guidelines and Technical Basis. Clarification made. 3) an example of a breaker failure Misoperation. **Response:** The drafting team has provided an example in the Guidelines and Technical Basis under "Composite Protection System – Breaker Failure Example" section, third bullet. Clarification made. We noted that the drafting team reverted to the non-capitalized 'fault' throughout most of the Application Guidelines. Yet in the listing of items that characterize a Misoperation on Page 23 (clean copy), the drafting team maintained the capitalization from the previous draft. Can the drafting team provided clarification on the proper use of the term? **Response:** The drafting team re-evaluated the general use of "fault" and the *Glossary of Terms Used in NERC Reliability Standards* definition of "Fault." The evaluation resulted in reverting certain occurrences that should refer to the glossary definition. Clarification made. In the 1st line under Unnecessary Trip - Other Than Fault on Page 26 (clean copy), delete the comma between 'to' and 'power'. **Response:** Punctuation correction made. Hyphenate 'out-of-service' in the paragraph following Example 7a on Page 27 (clean copy). **Response:** Punctuation correction made. Hyphenate 'high-side' in the 3rd line of Example 7b on Page 27 (clean copy). **Response:** Punctuation correction made.

Organization	Yes or No	Question 3 Comment
		Replace 'voltampere-reactive' with 'VAr' in the 3rd line of the paragraph under Non-Protective Functions on Page 27 (clean copy). **Response:** The usage of "static voltampere-reactive compensator" is consistent with the NERC style guide and IEEE usage for an SVC. No change made. We appreciate the explanation provided in the Extenuating Circumstances section. However, we believe that the standard should go beyond what is provided in the Sanction Guidelines. Why should an entity be held in violation in the event of multiple operations on its system during a natural disaster? There may not be an actual Misoperation but because an entity simply doesn't meet the purely administrative requirement of getting the evaluation done within a prescribed number of days, a violation has occurred. Recognition should be given in the standard for such events which withhold declaration of any potential violation until the entity has had sufficient time to 1) deal with the crisis at hand of rebuilding its system and 2) then performing the evaluations to determine if Misoperations occurred. This flies in the face of being innocent until proven guilty. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (timeframes) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.

Organization	Yes or No	Question 3 Comment
		In the 2nd paragraph below Example R1a, insert 'where a' such that the 1st line reads: 'For the case, where a BES interrupting device...'In the 4th paragraph below Example R1a, insert 'the' in the 7th line between 'if' and 'entity'. **Response:** Punctuation correction and clarification made. In the 1st paragraph below Requirement R3, break the two sentences in the 7th-9th lines (clean copy) into two separate sentences such that it reads: 'The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation and continue its investigation under Requirement R4.' **Response:** Corrections made. Bracket the 's' in 'CAP(s)' in the 4th line of the 2nd paragraph below Requirement R5 on Page 33 (clean copy). **Response:** Corrections made. Insert a 'to' between 'due' and 'resource' in the 4th line of the 2nd paragraph of Example R6c. **Response:** Corrections made. Regardless of the outcome of the capitalization of 'fault', it should be capitalized in the 1st sentence of Example R6d just like the 1st words of all the other examples given. **Response:** Corrections made.
American Electric Power	No	AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a "slow trip" type misoperation.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes this is described in the first paragraph of the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." No change made. AEP recommends adding a backup protection example to the application guidelines to illustrate how R2.2 would be applied. **Response:** The drafting team has provided an example(s) in the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." Clarification made. AEP recommends adding an example of a breaker failure misoperation to the application guidelines. **Response:** The drafting team has provided an example(s) in the Guidelines and Technical Basis under the heading "Composite Protection System – Breaker Failure Example." Clarification made.
Public Service Enterprise Group	No	In comments for the prior posting, we addressed a "consistency" reporting issue. See our comments and the SDT's response in the Consideration of Comments document on pp 27-28 and the SDT's response which is incorporated into the standard in various places. See the Application Guideline change on p. 31 of the redline version, which included this addition: "The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure, it may decide to identify the operation as a Misoperation and continue its investigation until the entity determines otherwise. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation."

Organization	Yes or No	Question 3 Comment
		The SDT's language above still allows entities too much latitude in the classification of an operation as a correct Operation or a Misoperation. The classification of an operation as a correct operation or a Misoperation is step 1 in the process. Only if the operation is determined to be a Misoperation is the cause of the Misoperation investigated (step 2). We suggest this guidance: "If the available evidence IS INSUFFICIENT to classify the operation as a Misoperation PRIOR TO THE INVESTIGATION OF THE CAUSE OF A POSSIBLE MISOPERATION, DO NOT CLASSIFY THE OPERATION AS A MISOPERATION." A Misoperation with "no cause found" is not equivalent to a correct operation, which is how an unreported Misoperation is interpreted. If an entity classifies an operation as a Misoperation and goes down that path to investigate the cause, it may well conclude that no Misoperation occurred; however, unless its original Misoperation classification is changed to reflect that result, the reported Misoperations will be overstated. Another entity with an identical operation may decide not to classify it as a Misoperation based upon the data available to it absent an investigation of the cause. For the sake of consistent reporting, the classification decision (correct operation or Misoperation) must be reached without a causal investigation, which only takes place if an operation is classified as a Misoperation. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. No change made.
Hydro-Québec	No	The purpose of the Standard shall be limited only to "Identify and correct the causes of Misoperations of Protection Systems affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System

Organization	Yes or No	Question 3 Comment
		Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC. **Response:** The scope of the current PRC-004-2.1a Reliability Standard applied to all BES Protection Systems; therefore, the Planning Coordinator or Reliability Coordinator do not need to identify specific BES Elements that affect reliability. No change made. Requirement R2 The owner of the interrupting device shall share any information he has, that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team contends that Requirement R2 only needs to require notification to the other owner(s) of the Composite Protection System. Creating Requirements for sharing information does little to improve reliability where information is already being communicated because the Requirements would have to prescribe what is shared and within what timeframes. No change made.
Nebraska Public Power District	No	See suggestion below in 4) **Response:** Please see response in Question #4.
Tacoma Power	No	In the Application Guidelines for Unnecessary Trip – Other Than Fault, the following paragraph seems out of place: “If a coordination error was at the remote terminal (i.e., set too fast), then it was an ‘Unnecessary Trip,’ category of Misoperation at the remote terminal.” This paragraph seems to focus on a scenario involving a fault. **Response:** The text was moved to “Unnecessary Trip – During Fault.” Correction made.

Organization	Yes or No	Question 3 Comment
		There is concern that, for a very small number of BES interrupting device operations, an entity could fail to identify (formally document) whether or not its Protection System component(s) caused a Misoperation. If this were to occur, it would likely be associated with apparently benign operations, so the likelihood that a misoperation would have occurred is low. Generally, misoperations garner a lot of attention within an entity, so they are generally hard to miss. Even if no misoperation occurred, an entity could be fined up to the maximum allowable for a Medium VRF and Severe VSL for failing to identify that its Protection System component(s) did not cause a Misoperation. The possibility for fines of this magnitude could drive potentially costly measures to ensure zero defects, even though BES reliability would not be impacted by failing to formally identify that an entity's Protection System component(s) did not cause a Misoperation. Tacoma Power agrees with the spirit of Requirement R1 but believes that compliance and enforcement should be assessed with failure (or tardiness in) identifying that its Protection System component(s) caused a Misoperation. Basically, if an entity does not determine whether or not a Misoperation occurred, they would be implicitly (by default) saying that a Misoperation did not occur. During an audit, if a BES interrupting device operation caused by a Protection System is uncovered for which no formal (explicit) identification according to Requirement R1 was made, the entity should only be found non-compliant (or penalized) if the CEA believes that a Misoperation did indeed occur. The purpose of the standard is to "identify and correct the causes of Misoperations of Protection Systems..." Perhaps this issue could be addressed in the Application Guidelines. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the

Organization	Yes or No	Question 3 Comment
		available evidence is inconclusive. The phrases "or not" have been removed from the VSLs to align with the Requirement. Even though Requirement R1, Part 1.1, stipulates that "the BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate," to what extent will entities be required to prove that BES interrupting device operations were not caused by a Protection System operation? The potential risk of failing to satisfy Requirement R1 seems high enough that entities may take costly measures to ensure zero defects, out of an abundance of caution, by excessively reviewing BES interrupting device operations. This additional cost could be better served in other areas to support BES reliability. Perhaps this issue could be addressed in the Application Guidelines. **Response:** The Requirement is written so that only Protection System operations that occur "under the circumstances Parts 1.1 through 1.3" be evaluated for Misoperation. No change made. In the Application Guidelines for Requirement R1, change "For the case,..." to "For the case in which a..." Furthermore, should this paragraph be included under the Requirement R2 portion of the Application Guidelines? **Response:** The drafting team provided an alternative clarification "For the case where a BES interrupting device…" Clarification made. The drafting team disagrees that this text needs to be included in the Guidelines and Technical Basis under Requirement R2. In the Application Guidelines for Requirements R1 and R3, change "The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion" to something like

Organization	Yes or No	Question 3 Comment
		“The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred.” The concern is that the CEA could require an entity to leverage all available data before determining that a Misoperation did not occur. **Response:** The drafting team added the clarification “In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred.” Clarification made. Tacoma Power appreciates the following paragraph in the Application Guidelines for Requirement R2: “A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.” **Response:** Thank you for your comment. In the Application Guidelines for Requirement R4, Example R4a, was the scheduling activity on 03/24/2014 considered to be the first investigative action pursuant to Requirement R4, or did the first investigative action pursuant to Requirement R4 occur on 4/10/2014?

Organization	Yes or No	Question 3 Comment
		Response: The drafting team added a clarification “as the first investigative” action to Examples R4b and R4b. Regarding Requirements R1, R3, and R4, is the date when an entity identifies that its Protection System component(s) caused a Misoperation the date that they officially make the identification? **Response:** Yes. As long as an entity is compliant with Requirement R1 or R3, as applicable, are they afforded some discretion as to the identification date? **Response:** The date a Misoperation is identified by the owner of the Protection System component(s) that caused a Misoperation would become the “official date” from which the Compliance Enforcement Authority would measure compliance with in Requirement R1 (or R3 for the notified entity). Note that if the “cause” of an identified Misoperation was not identified in Requirements R1 (or R3 for the notified entity), the entity is obligated under Requirement R4 to perform at least one investigative action at least once every two full calendar quarters after the Misoperation was first identified. No change made. It seems like the timeline for Requirement R4 should be based on 120 calendar days of the BES interrupting device operation, for Misoperations identified pursuant to Requirement R1, or the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, for Misoperations identified pursuant to Requirement R3. As written now, those entities who quickly identify Misoperations will have compliance obligations under Requirement R4 sooner. On the other hand, an entity that delays officially identifying a Misoperation could be looking for causes ahead of time such that they effectively bypass Requirement R4. Perhaps this issue could be addressed in the Application Guidelines. The objective here is not to make

Organization	Yes or No	Question 3 Comment
		the standard more complicated but to avoid misunderstanding that might surface during an audit. **Response:** Each of the time periods in the Requirements is discreet. Once a Misoperation is identified, the entity must either go to Requirement R4 (Misoperation without a cause) or Requirement R5 (develop a CAP because the cause is known). The drafting team added the “Requirement Time Periods” section to the Guidelines to provide additional clarity. Similarly, regarding Requirement R4 and R5, is the date when an entity determines the cause(s) of a Misoperation the date that they officially make the determination? **Response:** Yes. Perhaps this issue could be addressed in the Application Guidelines. Again, the objective here is not to make the standard more complicated but to avoid misunderstanding that might surface during an audit. **Response:** The drafting team provided clarification in the Guidelines and Technical Basis under the heading “Requirement Time Periods.” Clarification made. In the Application Guidelines for Requirement R6, change “...were postponed due resource...” to “...were postponed due to resource...” **Response:** The drafting team corrected the grammar. If manual intervention in response to a Protection System failure to operate is required, this could imply that both the primary Composite Protection System and remote backup Composite Protection System(s) failed to operate, assuming that remote backup could be configured reliably to detect the fault under the pre-fault power system conditions. Would this condition automatically mean that multiple Composite Protection Systems, potentially at multiple locations (both primary and

Organization	Yes or No	Question 3 Comment
		remote backup), misoperated? Perhaps this issue could be addressed in the Application Guidelines. **Response:** Under the scenario described above, multiple "Failure to Trip" Misoperations and would been likely to have occurred. No change made.
Independent Electricity System Operator	No	We do not agree with the part on Composite Protection System, for the reasons indicated under Q1, above. **Response:** Please see the response under Question #1.
Oncor Electric Delivery LLC	No	Since the last Standard draft, the SDT has added a new example on page 29 of the Application Guideline which states "Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush following a maintenance outage. Only the high-side breaker opens since the low-side breaker had not yet been closed. Since closing the breaker put the transformer bank into service, this is a Misoperation." Although this scenario would be an undesired trip, without the low side breaker closed the transformer will not feed load. With that said, tripping of the high side will not compromise reliability of the BES although it is undesirable. Oncor has not seen a perfect relay that will respond ideally during the reenergization of a transformer with magnetizing current. For the reason just described, the possibility of tripping a transformer unnecessarily during energization (with no load connected) is preferable to desensitizing the protection further such that it might not operate when necessary. **Response:** The drafting team recognizes this situation; however, the scenario should be classified as a Misoperation. If so, the entity may address not making any changes to the Protection System under Requirement R5 by making a declaration why

Organization	Yes or No	Question 3 Comment
		corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. No change made.
CenterPoint Energy	No	CenterPoint Energy recommends adding additional examples to help provide consistent reporting of Misoperations. Examples for Breaker failure events (stuck breaker) and additional examples of the more common "Unnecessary Trip – During Fault" category would be helpful. Additional examples would help clarify the interrelationship between the "Slow Trip – During Fault" and the "Unnecessary Trip – During Fault" categories. The following comments and additional examples are provided for consideration: **Response:** The drafting team has provided examples (see Examples 3b, 5b, and the 3rd bullet under the section "Composite Protection System – Breaker Failure Example") in the Guidelines and Technical Basis. Clarification made. Example 1e: The Composite Protection System for a bus does not operate during a bus fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System. **Response:** The drafting team has provided an Example 1e in the Guidelines and Technical Basis. Clarification made. Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical fault clearing time for a line fault in conjunction with a breaker failure (stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If

Organization	Yes or No	Question 3 Comment
		a generating unit's Composite Protection System operates due to instability caused by failure of a breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System. **Response:** The drafting team has provided this Example 3b, almost verbatim, in the Guidelines and Technical Basis. Clarification made. Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems due to dynamic stability reasons. The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a fault on this line, the two pilot systems fail to operate; and, the time-overcurrent scheme operates clearing the fault with no generating units or other Elements tripping (no over-trips). This event is not a Misoperation. **Response:** The drafting team has provided an Example 3c in the Guidelines and Technical Basis. Clarification made. Example 3d: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with the two independent high-speed pilot systems. During a fault on the line with the two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-

Organization	Yes or No	Question 3 Comment
		overcurrent scheme operates clearing the fault however, another line in the system trips (over-trips). The trip of the other line in the system is not an "Unnecessary Trip – During Fault" Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a "Slow Trip – During Fault" Misoperation, although the analysis and Corrective Action Plan would address the two pilot schemes failure to trip. **Response:** The drafting team notes this example is unnecessary due to its complexity therefore it has not been included in the Guidelines and Technical Basis. No change made. Example 5b: An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared fault on a different line is a Misoperation. The fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip of the line protection; therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation. **Response:** The drafting team has provided an Example 5b in the Guidelines and Technical Basis. Clarification made. Example 5c: A line connected to a switching station is protected with two independent high-speed pilot systems for reasons other than voltage or dynamic stability (e.g., short line length or to reduce backup clearing times for service reliability). The Composite Protection Scheme also includes step distance and time-overcurrent schemes in addition to the two pilot systems. The step distance and time-overcurrent schemes and Protection Systems of other line terminals are intentionally not

Organization	Yes or No	Question 3 Comment
		coordinated with the step distance and time-overcurrent schemes of this line because high-speed tripping is expected on the line with two independent high-speed pilot systems. During a fault on the line with two independent high-speed pilot systems, the two pilot systems fail to operate; however, the time-overcurrent scheme operates clearing the fault and, in conjunction, another line in the system trips (over-trips). The trip of the other line is not an "Unnecessary Trip – During Fault" Misoperation as miscoordination was expected for the conditions that occurred. The event on the line with the two pilot systems is a "Slow Trip – During Fault" Misoperation, although the analysis and Corrective Action Plan would address the schemes failure to trip. **Response:** The drafting team notes this example is unnecessary due to its complexity therefore it has not been included in the Guidelines and Technical Basis. No change made. Additionally, in the Application Guidelines, it appears the following paragraph at the end of the "Unnecessary Trip – Other Than Fault" examples is misplaced and could be deleted: "If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal." **Response:** The drafting team has relocated the text in the Guidelines and Technical Basis. Clarification made. CenterPoint Energy recommends adding the following wording as the last two paragraphs at the end of the examples for "Unnecessary Trip – During Fault" examples to parallel the wording for the "Slow Trip – During Fault" category: In analyzing the Protection System for Misoperation, the entity must also consider the "Slow Trip – During Fault" category to determine if an "slow trip" applies to the Protection System operation of an Element other than the faulted Element.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team disagrees that the suggestion "In analyzing…" provides additional clarity. No change made. If a coordination error was at the remote terminal (i.e., set too fast), then it was an " Unnecessary Trip – During Fault" category of Misoperation at the remote terminal. **Response:** The drafting team has provided an Example 5c in the Guidelines and Technical Basis. Clarification made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	The clarifications and additions to the Application Guide are helpful to the understanding of the standard. We recommend these type of guides be with all proposed Standards in the future. **Response:** Thank you for your comment. Results-based Standards (RBS) are designed to have an Application Guideline section to be retained with the adopted PRC-004-3 Reliability Standard upon approval.
National Grid	Yes	
Dominion	Yes	
Duke Energy	Yes	
SERC Protection and Controls Subcommittee	Yes	(1) It would be beneficial if examples in the Application Guidelines had different solutions other than just 'fixed capacitor'. **Response:** The drafting team contends that the examples illustrate different Corrective Action Plan approaches within the Requirement. Replacing the capacitor

Organization	Yes or No	Question 3 Comment
		simplifies the example to highlight the differences in what corrective actions are being taken. No change made. (2) It would be beneficial and we recommend the Application Guidelines remain with the Standard when published to provide easy reference for users. To provide clarity about the authority of the guidelines, the following note should be included similarly as written in other Standards that include Application Guidelines: "Note: These Application Guidelines for PRC-004-3 are neither mandatory nor enforceable." **Response:** Thank you for your comment. Results-based Standards (RBS) are designed to have a Guideline and Technical Basis section to be retained with the adopted PRC-004-3 Reliability Standard upon approval. Only the Requirements are mandatory and enforceable. No change made.
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	Yes	Application Guidelines: Overall, this document is very good in addressing the process. **Response:** Thank you for your comment.
ACES Standards Collaborators	Yes	(1) We agree that the Application Guidelines include improved examples and did clarify the intent of the drafting team. Furthermore, we support the intent in the

Organization	Yes or No	Question 3 Comment
		application guidelines. However, in some cases, the intent of the drafting team and the language of the requirements simply do not align. For example, language was inserted into the Requirement R3 discussion on page 31 to clarify that a registered entity is "to classify an operation as Misoperation if the available information leads to that conclusion" and "allows an entity to classify an operation as a Misoperation if an entity is not sure." Neither Requirement R3 nor Requirement R1 language provide this flexibility and is thus inconsistent with the language in the application guidelines. R1 and R3 are both very clear that the responsible entity has 120 days (for R3 or the later of 60 days after notification) to identify whether its Protection System operations were a Misoperation. This language is definitive. We do not see how this language allows an entity to classify an operation as Misoperation if it is not sure. Again, the requirement language states clearly that the responsible entity has to identify whether its Protection System components result in a Misoperation. There is no room in the language of the requirement for uncertainty. This further leads to a problem with R4 because R4 would require R1 and R3 to be violated since both require determination of whether a Misoperation occurred and R4 identifies a situation that can only occur after a violation of R1 or R3. Even the last Severe VSL for both R1 and R3 supports our argument. Failure to identify a whether or not a Protection System operation is a Misoperation is a Severe VSL. We suggest the drafting further refine Requirements R1, R3, and R4 collectively to match the intent demonstrated in the application guidelines. **Response:** The performance under Requirement R1 is that the entity identify Protection System operations that are Misoperations. The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. The drafting team contends that the language in the

Organization	Yes or No	Question 3 Comment
		Guidelines and Technical Basis provides clarity on the intent of the Requirements (i.e., R1 and R3), and is consistent with requirement language. No change made.
Florida Municipal Power Agency	Yes	FMPA appreciates the changes to the Application Guide and does feel the additional specificity was beneficial. We do, however, feel some sections are inconsistent with the revised Requirements and definitions in the standard. See our comments on the definition of "Misoperation" above. There may be some additional changes that are needed to the Application Guide to ensure it fully supports the revised Standard. **Response:** Please see our previous responses to FMPA comments. No change made.
Bonneville Power Administration	Yes	
Operational Compliance	Yes	
Exelon Companies	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	
Xcel Energy	Yes	
Wisconsin Electric Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	Entergy agrees with the SERC PCS comments to add Application Guideline examples other than "fixed capacitors", and that the Application Guideline should remain with the standard as a reference. **Response:** Please see response to SERC PCS comments. The Guidelines and Technical Basis remains with the standard. No change made.
American Transmission Company	Yes	
Kansas City Power & Light	Yes	
Ingleside Cogeneration LP	Yes	ICLP found the examples provided in the Applications Guidelines to be helpful. In addition, there is a sufficient diversity in scope that will act as a useful reference in the event that we suspect a Misoperation of one of our Composite Protection Systems may have taken place. **Response:** Thank you for your comment.
Idaho Power	Yes	
Southern California Edison Company	Yes	
Omaha Public Power District	Yes	
Cleco	Yes	
Northeast Utilities	Yes	The examples provided in the application guideline should be clarified when talking about unnecessary trips. It should be made clear that if any portion of a Composite

Organization	Yes or No	Question 3 Comment
		Protection System designed to protect one Element operates for a problem on another Element is considered a Misoperation. **Response:** The drafting team added a number of examples to clarify "unnecessary trips" in the Guidelines and Technical Basis. A Composite Protection System designed to protect one Element that operates for a problem on another Element is not necessarily a Misoperation. It could be a correct operation for a "Failure to Trip" elsewhere. Clarifications made to the Guidelines and Technical Basis.
Tri-State Generation and Transmission Association, Inc.	Yes	
Flathead Electric Cooperative, Inc.	Yes	still have trouble with how the word composite is being used, but do agree that the guidelines provide clarity on the drafting teams intent, unsure the compliance impact on the requirements **Response:** Thank you for your comment.
Wolverine Power Supply Cooperative, Inc.	Yes	
Texas Reliability Entity		No comments.

4. If you have any other comments on this Standard that were not provided in response to the previous questions, please provide them here:

Summary Consideration: The numerical values are approximate and are intended to provide a gauge of the concerns raised by industry stakeholders. The number of comments noted is analogous to the number of entities (e.g., five comments means five entities provided a comment). The following summary does not include items addressed in the previous summaries.

This section contained two individual comments that were different from previous summaries above. The comment suggested updating the flowchart wording based on clarifications made to the standard. The drafting team updated the draft PRC-004-3 Reliability Standard, its flowchart, and other related project documents for alignment such as the Implementation Plan which earlier posting revisions to the Misoperation definition failed to include.

Second, an entity pointed out that Evidence Retention section states 12 months is the required evidence retention period for the Requirements. The commenter also noted that the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The drafting team clarified the evidence retention periods are “a minimum of” time an entity is required to retain specific evidence to demonstrate compliance. The drafting team used NERC guidance in determining the appropriate minimum evidence retention periods.

The following multiple minority comments did not result in a clarification or revision to the draft PRC-004-3 Reliability Standard or other related project documents. Five comments by 15 individual presented general questions to the drafting team. The drafting team provided responses to these questions; for example, responses included as to whether the scenario was a Misoperation, not a Misoperation, or other response applicable to the rationale of certain Requirements. Three comments by 35 individuals requested either information on why topics like undervoltage load shedding (UVLS), and dispersed generation resources (DGR) concerning the new BES definition implementation, were not addressed in this version. The drafting team noted that it cannot base criteria or applicability in the proposed draft PRC-004-3 Reliability Standard based on projects that are in active development. Completing this version three will enable other drafting teams to address UVLS and DGR topics. Two comments represented by four individuals were concerned about the amount of time to develop a Corrective Action Plan (CAP) in Requirement R5. The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation and plan. Timeframes associated with any actions taken as a part of the evaluation of other Protection Systems are outside the scope of the standard. Two individual comments suggested significant changes to the standard. The drafting team contends that the draft PRC-004-3 Reliability Standard as written achieves the stated Purpose and therefore declines to make wholesale modifications to the Requirements. For example, there is no requirement to provide a CAP to the Reliability Coordinator in the current version PRC-004-2.1a Reliability Standard, although Regional procedures may have dictated the entity to do so.

The following are comments from single entities and individuals. There was a comment concerning the review and reporting of operations of jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. The drafting team contends that the reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., “data request”). Absent an agreement, all owners of a Protection System will have a compliance responsibility. Also, one comment asked when is a change to a CAP considered failure to implement. The drafting team noted that modifying a CAP does not constitute a failure to implement a CAP. According to Requirement R6, the audit approach to determining a failure to implement a CAP is addressed by the previously posted draft Reliability Standard Audit Worksheet (RSAW). As the entity completes the actions within a CAP, the entity will update the CAP periodically, thus the CAP will demonstrate implementation.

Another single entity commented that an entity in Requirement R3 should be afforded a full 120 calendar days to review its Protection System similar to entities that initiate reviews under Requirement R1. The drafting team responded that when an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted a minimum of 60 calendar days to identify whether it was a Misoperation and could be as much a 120 calendar days from the date the BES interrupting device operated depending on when notification occurs. A minimum time period that is less than 120 calendar days is provided on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

Another entity commented that an entity could forego performing Requirement R1 or R3 and conduct its review under Requirement R4. The drafting team contends that Requirements R1 and R3 do not preclude an entity from determining the cause of an identified Misoperation (Note: Requirement R2 is for notification to others.); however, Requirement R4 becomes applicable only after a Protection System operation is “identified as a Misoperation” under Requirement R1 or R3 and does not have an identified cause. Requirement R4 is an exception-based Requirement and is only performed when the entity did not identify the cause(s) of the Misoperation in its performance in either Requirement R1 or R3.

Last, a single commenter suggested shortening the performance time periods in Requirement R4 for performing investigative action. The drafting team contends that the periodic action balances the compliance burdens and focuses the entity’s effort on determining the cause(s) of the Misoperation while providing measurable evidence. In addition, certain planned investigative actions may require months or years to schedule and complete due to outages and other factors. Additionally, the drafting team contends that listing a defined time limit to complete the Requirement would actually decrease reliability. Shortening time limits would have the unintended consequence of causing an entity to discontinue its investigation. The Requirement allows the entity to either determine the cause or conclude its investigation when it is confident that a cause cannot be determined.

Organization	Question 4 Comment
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	a) The multiple timing process periods are an added burden and still unclear in the standard. However, the application notes do provide some guidance {R3}; **Response:** The drafting team provided clarification in the Guidelines and Technical Basis under the heading "Requirement Time Periods." Clarification made. b) The wording in R3 of the Process Flow Chart on the last page of the draft standard should match that of the requirement R6 (change "greater" to "later" in the chart). There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. **Response:** The drafting team has corrected the wording in the flowchart. Correction made.
ACES Standards Collaborators	(1) Example 3 on page 25 should be updated. The first sentence is inconsistent with the proposed definition of Misoperation. A failure of a line's Composite Protection System to operate as quickly as intended is only a Misoperation if another Element's Composite Protection System operation. Please append the following clause to the first sentence: "if another Element's Composite Protection System operated." **Response:** Clarification made. (2) The VSLs for R3 rely only on the 120 day portion of the language in the requirement. They do not include the "later of" language relying on 60 days if more than 60 days has passed since the original Protection System Operation. We suggest the VSLs should be updated accordingly reflect the requirement in totality.

Organization	Question 4 Comment
	Response: The VSL is based on tardiness regardless of whether the entity is afforded 120 calendar days from the operation of the BES interrupting device or 60 calendar days of notification by the initiating entity pursuant to Requirement R2. No change made. (3) To avoid requiring a registered entity from providing all BES interrupting device operations, the Compliance Assessment Approach for R1 in the RSAW needs to be modified to be consistent with the requirement and the evidence request section. The auditor should only sample BES interrupting device operations that meet the criteria Requirement R1 Part 1.1 through 1.3 and is provided as evidence in the evidence requested section. Please add “that meet criteria Requirement R1 Part 1.1 through 1.3” after “interrupting device operations” in the first and second rows of the RSAW’s Compliance Assessment Approach for R1. **Response:** The drafting team has provided the RSAW comment to NERC Compliance for consideration and modification. (4) Please update the RSAW’s Note to Auditor section to review the Application Guidelines section for Requirement R2 for small entities as well as vertically integrated utilities. The Application Guidelines make clear that small entities with a single protection engineer are not expected to provide notification requirements between the GO, TO and DP because they would already be aware since they evaluate all Protection System operations including transmission and generation. **Response:** This concern is addressed in the paragraph following Example R2b in the Guidelines and Technical Basis under the heading “Requirement R2.” The drafting team has provided the RSAW comment to NERC Compliance for consideration and modification. (5) Thank you for the opportunity to comment.
CenterPoint Energy	(a) In the Application Guidelines, CenterPoint Energy recommends changes to account for high-speed tripping for internal transformer faults by other types of protection systems (e.g., sudden pressure) that are not specifically included in the proposed definition of Composite Protection System. The following additional wording at the end of Examples 1a and 1b is suggested:

Organization	Question 4 Comment
	Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer fault is a Misoperation unless other protection schemes (e.g., sudden pressure) operated. Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer fault is not a “Failure to Trip – During Fault” Misoperation as long as another component of the transformer's Composite Protection System or other protection schemes (e.g., sudden pressure) operated. **Response:** The drafting team contends that the scenario that is described does not meet the definition of “Misoperation.” For a high impedance transformer Fault, the non-operation of a differential relay due to low Fault current levels is not a failure to operate as intended for protection purposes. A similar example (R1b) has been added to the Guidelines and Technical Basis. Clarification made. (b) The proposed Requirement R4 wording currently includes the following: “...shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes...”. CenterPoint Energy understands this wording is to provide a mechanism to continue investigative work to determine the cause of a Misoperation when the cause cannot be determined during the allotted time periods in Requirements R1 or R3. CenterPoint Energy recommends additional wording to allow the investigation to be completed in the quarter that the misoperation occurs (“partial quarter”) for cases where the investigation and tests, including any needed outages< can be completed in the partial quarter and suggests the following wording: “...shall perform investigative action(s) to determine the cause of the Misoperation at least once during the partial quarter when the misoperation occurs or every two full calendar quarters after the Misoperation was first identified, until one of the following completes...”.

Organization	Question 4 Comment
	Response: The drafting team contends that the suggestion does not provide any additional benefit over the current wording and may have the unintended consequence of shortening the time period for performance and being in compliance. See Example R4a in the Guidelines and Technical Basis for additional detail. No change made.
Florida Municipal Power Agency	2. FMPA does not feel our previous comment regarding the inherent problems with the concept of comparing Protection System performance to a single set of generic categories as tied to compliance was addressed. We feel many of the issues and challenges in this revised standard would easily be addressed by allowing entities to compare the performance of their relays with their Protection System Design Philosophy. In the absence of a mandatory electric reliability standard, this is how Utilities would determine “mis-operations” – did the Protection System/component perform according to the intended design? **Response:** The drafting team contends that design philosophies inherently include the principles of dependability and security. Each entity using its particular design philosophy would lead to less consistent classification of Misoperations. No change made. 3. In the Facilities section – what is the reason PRC-004-3 cannot use the same description of “Protection System” as PRC-005-2? Would these two standards not inherently be designed to cover the very same Facilities? **Response:** The draft PRC-004-3 Reliability Standard uses the defined term in the *Glossary of Terms Used in NERC Reliability Standards* without the additional level of specificity provided in PRC-005-2. The reasoning was to avoid a subsequent change to the draft PRC-004-3 Reliability Standard if additional equipment changed in the future. No change made. 4. FMPA accepts the SDT’s revised definition of Composite Protection system which no longer singles out step-distance/intentional remote backup schemes. However, we in general do not agree with the use of Composite Protection System in the standard. This term is being used to reduce what is considered a “Misoperation”. While FMPA supports more relaxed Requirements for

Organization	Question 4 Comment
	mitigating/remediating a Misoperation when another part of the Composite Protection System successfully prevents any negative impact to the BES, a Misoperation is still a Misoperation. If the goal is to keep statistics on how we are doing as an industry, we need to tie those statistics to basic characteristics that are less subject to interpretation and change. Misoperation should still be tied to the failure of equipment. The fact that a different part of the Composite system properly functioned is additional information. Again, we support the idea that a properly designed Composite Protection system should mean an entity does not necessarily need to make changes, but the Misoperation should still be tracked. **Response:** The drafting team contends that "Composite Protection System" should be based on the principle that an Element's multiple layers of protection are intended to function collectively. Also, the new definition supports consistent reporting of Misoperations under the Section 1600 data request because all entities, under the new definition, will be evaluating their Composite Protection Systems in the same manner. No change made. 5. What is the reason the defined Glossary term "Fault" has been replaced with "fault" throughout the document? **Response:** The drafting team re-evaluated the general use of "fault" and the *Glossary of Terms Used in NERC Reliability Standards* definition of "Fault." The evaluation resulted in reverting certain occurrences that should refer to the glossary definition. Clarification made.
Tacoma Power	Although the term is discussed in the Application Guidelines, consider formally defining the term "interrupting device." **Response:** The drafting team asserts that the phrase "BES interrupting device" is widely understood by industry and is described in the Guidelines and Technical Basis under the heading "Definitions." No change made. In Requirement R3, should "BES interrupting device(s)" be "BES interrupting device"?

Organization	Question 4 Comment
	Response: The parenthetical "s" is added here because the Protection System may have tripped more than one BES interrupting device. No change made. In Requirement R4, should "the cause" be "the cause(s)"? **Response:** Parenthetical "s" added. In Requirement R5, should "a cause" be "the cause" or "the cause(s)"? **Response:** This use of "cause" is singular because the Corrective Action Plan timing is triggered off of the "first" identified cause. No change made. In the Rationale for R6, change "tivities" to "activities." **Response:** Correction made.
American Electric Power	As currently written, R5 may be interpreted as requiring the entity to both develop a CAP and complete the evaluation of the CAP's applicability to other Protection Systems within 60 days. **Response:** Yes, that is correct. For large entities, or in cases where the evaluation requires equipment outages, completing the evaluation of applicability within 60 days could be impossible. R5 should be revised to clearly state that the entity is only required to develop a CAP within 60 days. There should be an option to include the evaluation within the CAP. This would enable entities to complete the evaluation as part of the CAP and within a time window that is tailored to the scope of the corrective action and quantity of potentially applicable Protection Systems. AEP supports the concept of evaluating a corrective action's applicability to other Protection Systems. **Response:** The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation. Timeframes associated with the execution of the evaluation are outside the scope of the standard. No change made.

Organization	Question 4 Comment
	However, the standard requirements provide no means of measuring what is an adequate evaluation. Without this, an auditor could question the adequacy of an entity's evaluation, decide that the entity's actions were not an evaluation and subsequently find the entity non-compliant with R5. We believe that the SDT's Application Guide examples were an effort to demonstrate what would be acceptable. However, the examples are not exhaustive and therefore do not eliminate the audit risk. AEP believes that subject matter experts are in the best position to determine evaluation scope and content. AEP recommends that in lieu of adding additional examples in the Application Guideline, the drafting team should consider the possibility of an auditor invalidating an evaluation. The requirement should be revised so that it places bounds on this scenario and provide entities with certainty in how R5 might be reviewed by an auditor. **Response:** The drafting team contends that there are no provisions within the draft PRC-004-3 Reliability Standard directing an auditor to determine the adequacy of an evaluation. No change made. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. AEP has chosen to vote in the affirmative despite our concerns regarding the CAP and evaluation within R5, and how their compliance would ultimately be determined by an auditor. **Response:** Thank you for your comment and support.
Independent Electricity System Operator	As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT's response indicates that UVLS has not been included in the proposed standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 - Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 - Under-Voltage Load Shedding Program Performance. We do not find this rationale sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated under the same light. Note that the SAR for Project PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT to

Organization	Question 4 Comment
	coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS. **Response:** Undervoltage load shedding (UVLS) has not been included in the draft PRC-004-3 Reliability Standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different Reliability Standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made.
Bonneville Power Administration	BPA believes that there is one other gap that has not been identified. This is the case where a TO, GO, or DP owns a BES interrupting device that operates, but does not own any of the Composite Protection System. This is a real scenario. In this situation, the owner of the BES interrupting device is not subject to R1 because R1.2 is not true, i.e. the owner of the BES interrupting device does not own all or part of the Composite Protection System. Likewise, the owner of the BES interrupting device is not subject to R2 because R2.1.1 is not true, i.e. the owner of the BES interrupting device does not share ownership of the Composite Protection System -- they don't have any ownership of the Composite Protection System. With the owner of the BES interrupting device not subject to R1 or R2, the operation of the BES interrupting device would not be investigated. BPA suggests that this problem could be remedied with a slight change in language to R2.1.1 as follows: "The BES interrupting device owner does not own any of the Composite Protection System or shares the

Organization	Question 4 Comment
	Composite Protection System ownership with any other owner." This change would require an owner of a BES interrupting device that does not own any of the Composite Protection System to provide notification of the operation to the owners of the Composite Protection System within 120 days per R2.1 so that they could then investigate the operation. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made.
Cleco	Cleco will continue to vote "Negative" as long as the SDT continues to support in R1 and R2 the deadline of 120 days to determine if an operation is a misoperation. There should be exceptions built into the standard when there are circumstances that create numerous outages such as ice storms or hurricanes. For example; In FAC-003, a footnote allows for circumstances that are beyond the control of the Registered Entity. Also, the standard should apply to all protection systems and the SDT should not exclude SPS or RAS. **Response:** We understand your concern, however, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). No change made.
Tennessee Valley Authority	Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system

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	configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording that states something similar to the following. In the event that the reporting entity is the victim of a weather related Category 4 or 5 event, 90 days are added to each of the required deadlines for misoperations caused by the weather related event. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (timeframes) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Electric Reliability Council of Texas, Inc.	ERCOT is concerned about Requirement 1 that allows entities 120 days to identify a misoperation. ERCOT believes this might negatively impact the reliability of the grid. Currently, entities have the responsibility to analyze disturbances to identify misoperations. A misoperation could indicate a greater threat to reliability and that threat could exist, unknown, for several months while entities make determinations if operations are truly a misoperation. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load and the opportunity to identify any Misoperations which were initially missed. No change made.

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	The responsible entity under the new Standard will track misoperations and develop Corrective Action Plans (CAPs). There is no responsibility for the entity to share that information with Reliability Coordinators who have the responsibility for the wide area view of their Reliability Coordinator area. ERCOT is also concerned that while the responsible entity may develop CAPs, there is no responsibility of coordination of the CAP with other potentially affected entities. **Response:** If a CAP results in a modification to a Protection System, PRC-001 – System Protection Coordination requires coordination with other owners. No change made. ERCOT is therefore recommending the following: R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 24 hours, identify whether its Protection System component(s) caused a Misoperation on an element that is part of an Interconnection Reliability Operating Limit under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 2 business days, identify whether its Protection System component(s) caused a Misoperation on an element at 200 kV or more under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]

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	2.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 2.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 2.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R3. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 5 business days, identify whether its Protection System component(s) caused a Misoperation on an element that is a BES element under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 3.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 3.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 3.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation. R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the CAP developed in R5, to the Reliability Coordinator with the expected date of completion, how the Composite Protection System will operate until the CAP is completed and detailed information of how the entity will coordinate the CAP with other affected entities if applicable. **Response:** The drafting team contends that the draft PRC-004-3 Reliability Standard as written achieves the stated Purpose and therefore declines to make wholesale modifications to the Requirements. There is no requirement to provide a Corrective Action Plan to the Reliability Coordinator in the current version (i.e., PRC-004-2.1a) of the standard, although Regional procedures may have dictated the entity to do so. No change made.

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Wisconsin Electric Power Company	Facilities, Section 4.2.1, should have an exclusion for individual dispersed generators, or have its applicability limited to the point where the generators are aggregated to greater than 75 MVA. It is critical for the PRC-004-3 SDT to coordinate with the SDT for Project 2014-01, Standards Applicability for Dispersed Generation Resources, to assure that the new standard will have appropriate applicability consistent with BES reliability. **Response:** It is not practical to implement changes to the draft PRC-004-3 Reliability Standard based on another project that is in active development. The standard drafting team for Project 2014-01 is aware of this concern and will be addressing the topic following adoption of the draft PRC-004-3 Reliability Standard. No change made.
Flathead Electric Cooperative, Inc.	Generally feel that the requirements should be the sole place where the actual compliance requirements appear. Lot of information in measures, application guidelines, definitional changes that are not technically requirements but may be treated as such depending upon the audience. **Response:** The Requirements of the draft PRC-004-3 Reliability Standard are the only requirements an entity must follow to be compliant. Other information such as Measures and Guidelines and Technical Basis support measurement, provide clarity, and intent of the standard. No change made.
Tri-State Generation and Transmission Association, Inc.	In response to Tri-State's previous concern to the review and reporting of operations of jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. The SDT stated "While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results" appears to require all entities to report the operation giving double jeopardy to each misoperation on jointly-owned Composite Protection System components, unless a contract speaks to the designated "Compliance Entity". Typically compliance contracts take some time to come to fruition.

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	Is it the drafting team's intent that misoperations be reported by multiple entities in this situation until a contract is finalized? **Response:** The reporting of Misoperations is outside the scope of the draft PRC-004-3 Reliability Standard and is being addressed by the NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., "data request"). Absent an agreement, all owners of a Protection System will have a compliance responsibility. No change made.
Pepco Holdings Inc	None
Oncor Electric Delivery LLC	Oncor initially balloted affirmative; however, based on the changes in the Application Guide, Oncor's ballot position has changed. Oncor's comments have been provided for the SDT's consideration (response to Question #3) Oncor requests the SDT please consider the additional comment below: In "R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation under the following circumstances: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning] 1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and 1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation."

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	The circumstances mentioned in 1.1 and 1.3 cause confusion when you do not have a protection system component cause the BES interrupting device operation in the event a BES device is operated by manual intervention. Oncor recommends that 1.3 be written to state: The BES interrupting device owner identified that its Protection System component(s) were designed to cause the BES interrupting device(s) operation. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 to address this oversight. Part 1.3, as intended, now includes “manual intervention” as a circumstance. Clarification made. The request below is an outstanding request from Oncor’s previous comment period: The Extenuating Circumstances process, as outlined on page 30 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the Reliability Assurance Initiative Oncor recommends the evaluation of an Extenuating Circumstance be initially reviewed by Compliance Operations in accordance with the system-wide and regional risk framework, an entity’s inherent risk assessment and controls to ensure extenuating circumstances are not evaluated as a “one size fits all” and findings are determined in accordance with RAI versus an automatic Enforcement path. Furthermore, Oncor recommends the Registered Entity be allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity. **Response:** The drafting team does not have the ability to make modifications to the Rules of Procedure. No change made.
Exelon Companies	Paraphrasing many commenters from draft 4, Exelon agrees emphasis on due dates from the time of an operation be reconsidered. There is a significant administrative burden imposed by the proposed approach not commensurate with gains in reliable operations. The drafting team can review previous comments to this effect as well as references to the use of “calendar” as used in the PRC-005

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	supplemental reference to preclude the need to have reviews done by a specific date. We disagree with the SDT response that timeframes as proposed are required to force entities to be diligent about identifying and correcting misoperations. **Response:** The drafting team contends that the timeframes should be measured from the operation date of the BES interrupting device which makes the use of calendar months or quarters difficult. The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load. The Protection System Maintenance and Testing Reliability Standard (i.e., PRC-005) is based on recurring activities over longer periods than the draft PRC-004-3 Reliability Standard, which is event driven. No change made.
Manitoba Hydro	R6 -when is a change to a CAP considered failure to implement and therefore a violation of R6 (since R6 both requires implementation of a CAP and allows changes to the CAP) **Response:** The drafting team contends that modifying a CAP does not constitute a failure to implement a CAP. According to Requirement R6, a failure to update the CAP when actions or timetables change until completed is a failure to implement the CAP. No change made.
Northeast Power Coordinating Council	Regarding Section 5: Background (page 6), additional justification to explain the application of the standard would be beneficial. As indicated in our previous comments, we disagreed with the omission of UVLS while UFLS is included. The SDT's response indicates that UVLS has not been included in the proposed standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. This rationale is not sufficient to justify the inclusion of UFLS but exclusion of UVLS since both need to be assessed and treated the same. Note that the SAR for PRC-022-1 is being revised to include UFLS. We suggest the PRC-004 SDT coordinate with the PRC-022 SDT to apply a consistent approach to addressing Misoperations of UFLS and UVLS.

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	Response: Undervoltage load shedding (UVLS) has not been included in the draft PRC-004-3 Reliability Standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different Reliability Standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made. Requirement R1 does not work for the case where manual intervention to operate the BES device was required. Parts 1.1 thru 1.3 are all ANDS. Part 1.3 requires the Interrupting Device to be operated by the Protection System. This conflicts with the idea in Part 1.1 of MANUAL intervention. If an operator manually opens a breaker because the Composite Protection System does not clear a fault then the Protection System could not have operated the interrupting device. Therefore the threshold R1 would not be met and no identification is required even though the Composite Protection System may have failed-to-trip. Suggest Part 1.3 be revised to read: The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation; or manual intervention was required to operate the BES interrupting device because its Protection System failed to operate. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 that it includes manual intervention. Clarification made.

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	Requirement R1 can be rephrased to provide clarity to the relationship of Parts 1.1 thru 1.3 to R1. Present phrasing has the added phrase, under the following circumstances, following Misoperation where it can ambiguously modify Misoperation. Clearly the intent is to describe the circumstances that a BES device owner has to embark on a process to identify a Misoperation. There are two inputs prior to beginning the process of identification; first the operation of a BES interrupting device occurs and second that the attributes of Parts 1.1 thru 1.3 are met. It would be clearer to place the reference to Parts 1.1 thru 1.3 prior to the word identify. Suggest Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated, and where such operation conforms to Parts 1.1 thru 1.3, shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation. **Response:** The drafting team made the clarification in Requirement R1.
National Grid	Second part of sub-requirement R1.1 “The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate” seems to contradict with sub-requirement R1.3 “The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation”. R1.1 and R1.3 cannot be met at the same time. **Response:** The drafting team made a clarification to Requirement R1, Part 1.3 that it includes manual intervention. Clarification made. An entity which receives notification of the BES interrupting device(s) operation in requirement R3 is allotted between 60 and 120 calendar days. However, the BES interrupting device(s) owner(s) are allotted 120 calendar days. Receiving entity also should be allotted full 120 calendar days counting from the day it receives notification. **Response:** When an entity receives notification of a Protection System operation by the BES interrupting device owner, the Protection System owner is allotted at least 60 calendar days to

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	identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components. No change made. Requirements R1, R2, and R3 are assuming that an entity will make an attempt to determine the cause(s) of a Misoperation. However, an entity can choose to make no effort until requirement R4 becomes applicable. It is suggested to expand requirements R1, R2, and R3 with the obligation for an entity to make an effort to determine the cause(s) of a Misoperation before requirement R4 takes place. **Response:** Requirements R1 and R3 do not preclude an entity from determining the cause of an identified Misoperation. (Note: Requirement R2 is for notification to others.) Requirement R4 becomes applicable only after a Protection System operation is “identified as a Misoperation” and does not have an identified cause. Requirement R4 is an exception-based Requirement and is only performed when the entity did not identify the cause(s) upon the identification of the Misoperation in either Requirement R1 or R3. No change made.
Public Service Enterprise Group	See the Consideration of Comments document, pp. 76-77. We interpreted that the SDT agreed to our proposed changes to R3; however it was not reflected in this draft. **Response:** The drafting team meant to explain that it revised the Guidelines and Technical Basis to provide a more detailed explanation of the “two full calendar quarters” rather than change the Requirement R4 language to “180 calendar days.” No change made.
Texas Reliability Entity	Texas Reliability Entity is voting Negative on this standard due to the concern that the reliable operation of the BES is not ensured by this standard (as written) because the allowable time periods for investigating and correcting are too long and investigative actions are not required before R4. Please consider the following comments and recommendations.

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	1) Recommend changing the allowable time for identification of a Misoperation to 60 days for R1 and R2. The 120 identification period (in R1 and R2) coupled with the additional allowance in R3 of 60 days means a Misoperation may not be determined up to 179 days after the interrupting device operation. The risk to the BES is still undetermined during this time period and actions should be taken to identify if a Misoperation occurred more expeditiously. **Response:** The drafting team concluded that most Protection System reviews would occur soon after a BES interrupting device operation. The 120 calendar days is a maximum time allowance and provides for seasonal variations in operations and work load and the opportunity to identify any Misoperations which were initially missed. No change made. 2) Suggest revising language in Requirements 1 and 3 to include investigative actions: [each entity] "shall perform investigative actions to identify whether its Protection System component(s) caused a Misoperation" The proposed language would clarify the expectation that investigations are on-going prior to R4. As written, the standard conceivably allows for a period of up to 120 days before investigative actions are performed. Although the application guidelines for R4 states that an entity "is expected to use due diligence in taking investigative action(s) to determine the cause(s)..." and that R4 "provides the entity a mechanism to continue its investigative work..." the standard does not require an entity to do investigative work before R4. **Response:** The drafting team contends that some level of investigation will be necessary to identify a Misoperation. Once a Misoperation is identified (without a cause), Requirement R4 becomes in effect. No change made. 3) Recommend changing the performance of investigative actions to at least once every calendar quarter in R4. If a Misoperation is confirmed (through steps taken in R1 – R3) then the risk to the BES continues until such time as a cause is found and can be corrected. The application guidelines state that periodic investigative action minimizes compliance burden and focuses the entity's efforts on determining cause, Texas Reliability Entity asserts that the time period of at least one investigative action every two full calendar quarters (180 days) is not adequate to protect reliability.

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	Response: The drafting team contends that the periodic action balances the compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. In addition, certain planned investigative actions may require months or years to schedule and complete due to outages and other factors. No change made. 4) In order for R4 to be measurable there should be a stated time horizon (per NERC's Acceptance of a Reliability Standard, Item 7, first bullet). The investigation may end either by identification of the cause of the Misoperation or a declaration that no cause was found. Suggest adding requirement to either determine the cause or make the no cause found declaration within 365 days after interrupting device operation. **Response:** The drafting team contends that listing a defined time limit to complete the requirement would actually decease reliability. It would have the unintended consequence of causing entity to discontinue its investigation. The requirement allows the entity to either determine the cause or conclude its investigation when it is confident that a cause cannot be determined. The Time Horizons are used by Compliance Enforcement Authority in determining penalties and does not impact the timing or measurability of the requirement. No change made. 5) The investigation and CAP timelines (as written) exceed 12 months so the evidence retention period of 12 months is insufficient. Evidence of investigative actions may be disposed of before corrective action is completed; meaning that a full record of an interrupting device operation may not be available for review by the CEA. In addition, the 12 month evidence retention schedules for R5 and R6 mean that an entity may not have any evidence to prove compliance to a CEA during an audit (which can be several years after a Misoperation). **Response:** The drafting team clarified the time periods for retaining evidence is "a minimum of" and also added for Requirements R1-R4. The "development" was revised to "completion" to reflect the intended retention period. Clarification made.

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MRO NERC Standards Review Forum	Thank you for the opportunity to comment.
Nebraska Public Power District	The 1.2 Evidence Retention section states 12 months is the required evidence retention period for the requirements. It also notes that "the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." I would recommend that the evidence retention be longer since it will be difficult to reproduce audit period evidence if it has been discarded. **Response:** 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 CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit. The drafting team used NERC guidance in determining the appropriate evidence retention periods. See the document *Background Information on Quality Reviews*, February 7, 2012 (http://www.nerc.com/files/Background_Document_20120207.pdf). No change made. Project 2014-01 Dispersed Generation has noted that PRC-004 needs to be reviewed and updated to direct the industry as to the appropriateness of the BES elements that require misoperation analysis and documentation related to dispersed generation. It is recommended to consider adding these changes rather than issuing multiple versions of this standard unless there is a serious reliability risk with the existing PRC-004 standard. **Response:** The drafting team recognizes that having multiple versions of a Reliability Standard is not ideal; Additionally, it is not practical to implement changes to the draft PRC-004-3 Reliability Standard based on another project when it is in active development. Because of this, the draft PRC-004-3 Reliability Standard must move forward for approval so that other projects can use a final version as a basis for any proposed inclusions or revisions.

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	The Draft 5 Application Guidelines states "The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5." There are concerns that some CAP evaluations including programs for other locations could be open for long periods of time creating significant audit tracking burdens. Is it acceptable in some cases if a CAP for correcting the issue with equipment that misoperated also has an evaluation to only identify other locations that have a similar issue and once other locations are identified the CAP is considered completed and no other audit tracking is required? If this is acceptable this may be beneficial for cases where there is an issue with a large number of similar breakers, relays, communication schemes, potential devices or current transformers that might be widespread on some systems requiring years to replace or update as part of a program or several programs. If the above is not acceptable as the standard is written consider adding a 3rd bullet to R5 to allow a CAP for the specific misoperations and a requirement to identify other locations or allow a declaration that can be used for creating a CAP for other locations that will be considered separately from PRC-004-3. **Response:** Yes, the drafting team believes your approach meets the intent of Requirement R5. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5. Timeframes and actions associated with the execution of the evaluation are outside the scope of the standard. No change made.

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	There are still concerns with including manual intervention as part of R1 since most appear to agree it is rare. Can the SDT provide some thoughts on the best way to guarantee that a manual intervention is duly tracked and provided to the protection departments for review? Perhaps dispatch centers need to have a procedure or process that specifically states “any manual intervention for a failed protection system must be reported to the appropriate protection system owner”. Would this be considered a reasonable process approach to satisfy the requirements of auditors that the proper misoperation procedures are in place? It may be that the manual intervention requirement is better suited to the SPS, UFSL, UVLS or plant shutdown schemes since those schemes are more likely to allow operators time to react rather than having manual intervention a part of all types of system operations as it is in R1. Perhaps there are cases where an operator has taken action for a transmission line fault or issue that did not clear with primary/secondary/breaker failure or backup remote clearing but I am not aware of any of these cases. It may be better to clarify the types of practical manual interventions that are intended to be covered by the standard or remove it and place it in another standard mentioned above with clarification for the most practical cases where this should be tracked to simplify the misoperation process documents utilities would likely need to have in place. There is concern that an auditor will have the latitude to ask how you guarantee that you are aware and tracked all manual interventions for protection system failures that have taken place on your system in the last audit period and this could be difficult to prove. **Response:** The drafting team asserts that manual interventions do not necessarily need to be tracked, but they are a condition for which a Protection System must be reviewed for Misoperation. Since it is such an unusual occurrence, the drafting team would expect the entity to be informed of such an operation. An example of manual intervention is a Generator Owner intervening to trip a unit where the operator believes a Protection System failure to operate has occurred. No change made.

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SERC Protection and Controls Subcommittee	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. **Response:** Thank you for your comment.
Omaha Public Power District	The Omaha Public Power District (OPPD) is still concern with the 60-day requirement to develop a Corrective Action Plan (CAP) for an identified misoperation. This timing is not practical, and depending on the time of the year, budget cycle, scope of work, 60 days is not sufficient to obtain funding for CAPs. Also, the first bullet under R5 would require evaluation of the applicability of all CAPs to all BES locations which, depending on the CAP, could be overly burdensome. As worded, a wiring or setting error would require that all wiring and all settings at all BES locations be checked. The evaluation should be limited to CAPs related to scheme logic or relay design deficiencies. OPPD proposes that 180 days (6 months) is a sufficient timeframe to practically develop a CAP addressing both operational and budgetary coordination. **Response:** The drafting team contends that 60 calendar days is an adequate amount of time to develop a high level evaluation. Timeframes associated with the execution of the evaluation are outside the scope of the standard. No change made.
Northeast Utilities	The Unnecessary Trip definitions as written are unclear and seem to indicate that the total compliment of the Composite Protection System. Suggest the following clarifications; Unnecessary Trip - During Fault - An unnecessary operation of any Protection System of a Composite Protection System for a Fault condition on another Element. Unnecessary Trip - Other Than Fault - An unnecessary operation of any Protection System of a Composite Protection System for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

Organization	Question 4 Comment
	Response: The drafting team added "Composite" to the definition of "Misoperation" for categories 5 and 6 based on comments during the draft 4 posting (e.g., see RFC – Question 1). This was done for consistency within the definition of "Misoperation." No change made.
SPP Standards Review Group	UFLS is mentioned in 4.2.2 of the Applicability Section but there is no mention of UVLS. Should it be included here? **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Adding UVLS in PRC-004-3 at this point would create unforeseen issues with having Requirements in two different standards address the same activity. The purpose of the UFLS project is to address an outstanding FERC directive and review PRC-006-1 to determine if any steady state modifications are appropriate (i.e., Paragraph 81 criteria and recommendations of the Independent Expert Review Panel). Specifically, the other project's standard drafting team will revise PRC-006-1 to address the directive included in FERC Order No. 763 and to provide for clear, unambiguous design and documentation requirements for automatic UFLS programs. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard. The drafting team added additional text to the background to explain both UVLS and UFLS. Clarification made. We would suggest that the drafting team consider incorporating the evaluation of the CAP's applicability mentioned in the first bullet under Requirement R5 into the CAP itself. This falls in line with the second bullet in the Requirement which is included in the CAP and gets the burden of making the evaluation concurrently with the development of the CAP out of the way. The evaluation could delay the completion of the CAP.

Organization	Question 4 Comment
	Response: By definition the CAP consists of actions to remedy a specific problem (i.e., the Protection System Misoperation). Because the CAP is a specific plan, the evaluation is structured as a separate activity. No change made. References to days should be calendar days and they should be hyphenated; for example 30-, 45-, 60-, or 120-calendar days. Similarly, references to months should be treated in the same manner; for example 12-calendar months. **Response:** The use of a hyphen as suggested is not consistent with the NERC style guide. No change made.
PPL NERC Registered Affiliates	We continue to disagree that stating whether or not a Misoperation occurred (per R1) and (under some circumstances) what the cause was (per R3) should be due within 120 days even though identifying the cause may take much longer or may even prove impossible (per R4). That is, the SDT apparently prefers where uncertainty exists to classify events as Misoperations and retract the declaration if later findings show otherwise, while we prefer the present approach of not assuming a Misoperation if evidence to support such a conclusion is lacking. The difficulty foreseen regarding the SDT's approach is that dated evidence is required in M1 that an entity, "identified the Misoperation... within the allotted time period," and in M3 that it, "identified whether its protection System component(s) caused a Misoperation within the allotted time period," while all we may be able to say after 120 days is that we don't know why an event happened. R4 describes what to do in such a situation, but it does not retract the obligation to provide impossible-to-obtain evidence satisfying M1 and M3. **Response:** Requirements R1 and R3 do not require, but do not preclude an entity from determining the cause of an identified Misoperation. (Note: Requirement R2 is for notification to others.) Requirement R4 becomes applicable only after a Protection System operation is "identified as a Misoperation" and has not identified the cause(s). Requirement R4 is an exception and is only

Organization	Question 4 Comment
	performed when the entity did not identify the cause(s) upon the identification of the Misoperation in either Requirement R1 or R3. No change made. **Response:** The requirement does not preclude the entity from using judgment in the classification of the operation if the available evidence is inconclusive. No change made.
JEA	We disagree with the 60 day limit in R5 to develop a CAP and think it should be 180 days. **Response:** The drafting team believes that 60 days is sufficient to develop a CAP including its applicability to other Protection Systems as there is opportunity to update the CAP in Requirement R6 as needed. The drafting team believes that issues such as cost/benefit scenarios, resource coordination, scheduling, and funding procurement can be considered while developing the schedule of the CAP. No change made.
Southern California Edison Company	With respect to Requirement 5 on the Corrective Action Plan requirements, we are concerned that an entity's declaration that no corrective action will be taken without supporting evidence, could leave a system problem unresolved. **Response:** The drafting team contends that each entity when making a declaration will have to explain "why corrective actions are beyond the entity's control or would not improve BES reliability." This is consistent with the Requirement and Measure. No change made. The decision that a Corrective Action Plan is unnecessary, or the development of a Corrective Action Plan, are both complex actions that should be done jointly by respective owners of the composite protection system in a consensus-building manner. The failure to reach consensus on Correction Action Plans can leave the problem unresolved. **Response:** The drafting team contends that the requirements are structured in a manner that each entity that has identified a cause of a Misoperation of its Protection System components must develop a CAP according to Requirement R5. Other entities are required to develop a CAP if they

Organization	Question 4 Comment
	identified that their components caused a Misoperation, unless corrective actions would not improve BES reliability or are beyond the entity's control. If a CAP results in a modification to a Protection System, PRC-001 – System Protection Coordination requires coordination with other owners.
Wolverine Power Supply Cooperative, Inc.	Wolverine's position is that the PRC-005 standard sufficiently covers the maintenance and testing requirements for protection systems. Because of this maintenance performed, it is not necessary to perform a detailed engineering analysis of every BES protection system operation. Wolverine's position is to only perform an engineering review of protection system operations if there is an apparent misoperation, for example, an over reach condition, failure to trip, etc. These are easily identified by transmission operators if only the correct facility cleared. To use a protection system operation to verify if a primary and backup protection system work properly seems to conflict with the requirement in PRC-005, which is written to ensure protection systems are maintained so they work properly. **Response:** The drafting team notes that the NERC State of Reliability, May 2013 states, "Key Finding 4: Protection System Misoperations are a significant contributor to disturbance events and automatic transmission outage severity. Incorrect settings/logic/design errors, relay failures/malfunctions, and communication failures are the three primary factors that result in such Misoperations." No change made.

END OF REPORT

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. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.
6. Draft 4 of PRC-004-3 was posted for a 45-day additional comment period from January 17 – March 11, 2014 and an additional ballot in the last ten days of the comment period from February 2 – March 11, 2014 under the new Standards Process Manual (Effective: June 26, 2013).
7. Draft 5 of PRC-004-3 was posted for a 45-day additional comment period from May 16 – July 9, 2014 and an additional ballot in the last ten days of the comment period from June 20 – July 9, 2014.

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft 6 of PRC-004-3 – Protection System Misoperation Identification and Correction for a 10-day final ballot.

Anticipated Actions	Anticipated Date
10-day Final Ballot	July 2014
BOT Approval	August 2014

Effective Dates

The standard, the revised definition of “Misoperation,” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of "Misoperation," and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	

2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	TBD	Adopted by Board of Trustees	Revision under Project 2010-05.1

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 *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NERC Glossary.

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.

6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**
2. **Number:** PRC-004-3
3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.
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 for BES Elements, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and

[1] For additional information and examples, see the “Non-Protective Functions” and “Control Functions” sections in the Application Guidelines.

correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a “fill-in-the-blank” standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms “specified time” and “abnormal condition” are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information (“data request”). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard’s applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one “Failure to Trip – During Fault” Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – During Fault” category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The “Failure to Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the “Slow Trip – Other Than Fault” category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

Example 3a: A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

Example 3b: A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element’s Composite Protection System. If a generating unit’s Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an “Unnecessary Trip – During Fault” Misoperation of the generating unit’s Composite Protection System. This event would be a “Slow Trip – During Fault” Misoperation of the breaker's Composite Protection System.

Example 3c: A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase “resulted in the operation of any other Composite Protection System” refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the “Unnecessary Trip – During Fault” category to determine if an “unnecessary trip” applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

Example 4: A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.
>
> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay’s characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example 6e: A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of “Misoperation.”

The “on-site” activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line’s relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity’s investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[7] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.
>
> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity’s control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity’s transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

> **Example R5i:** During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

> **Example R6a:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

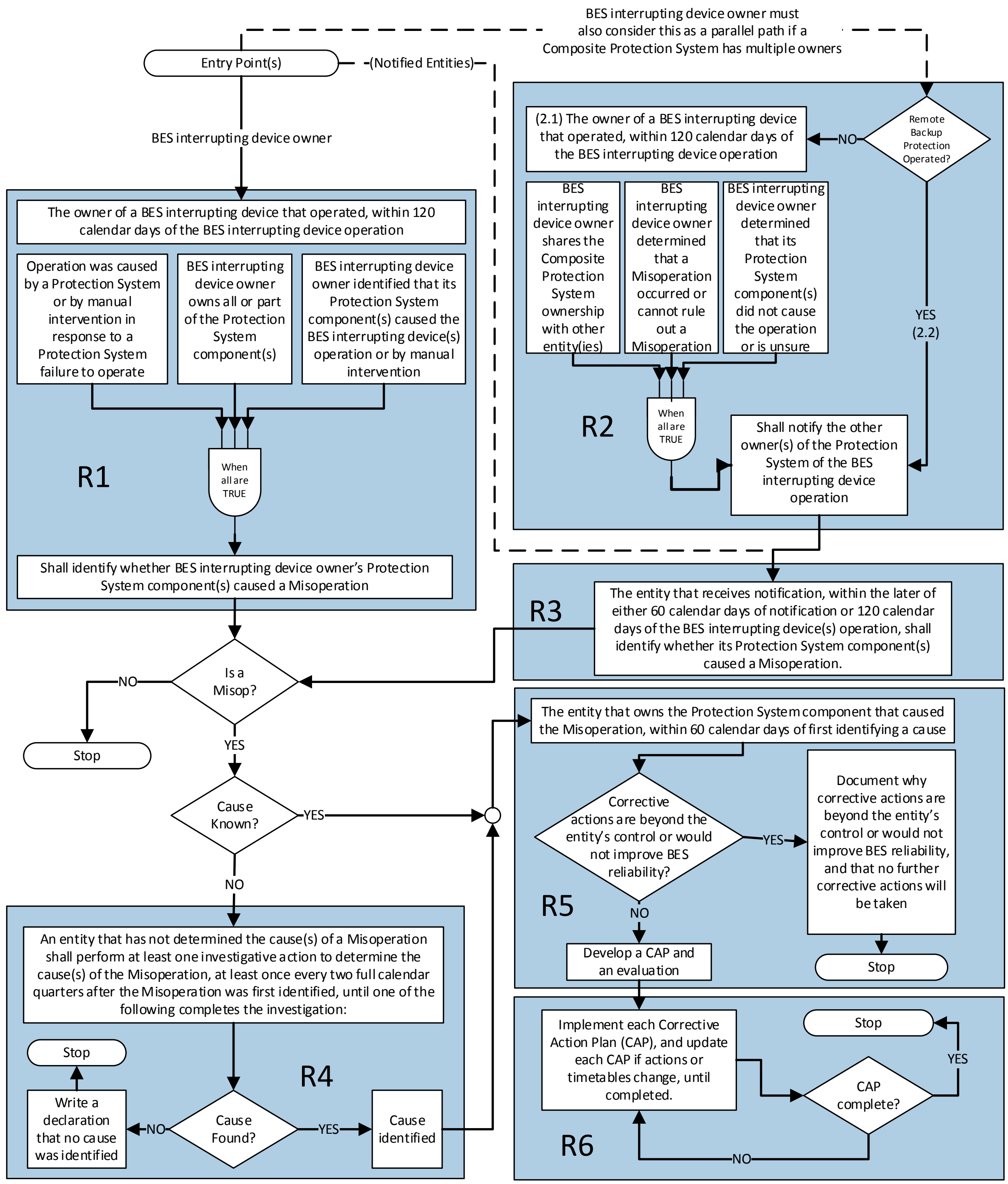
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



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. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.
6. Draft 4 of PRC-004-3 was posted for a 45-day additional comment period from January 17 – March 11, 2014 and an additional ballot in the last ten days of the comment period from February 2 – March 11, 2014 under the new Standards Process Manual (Effective: June 26, 2013).
7. Draft 5 of PRC-004-3 was posted for a 45-day additional comment period from May 16 – July 9, 2014 and an additional ballot in the last ten days of the comment period from June 20 – July 9, 2014.

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft ~~5~~6 of PRC-004-3 – Protection System Misoperation Identification and Correction for a ~~45~~10-day ~~additional comment period and additional~~final ballot~~ in the last ten days of the comment period under the new Standards Process Manual (Effective: June 26, 2013).~~.

Anticipated Actions	Anticipated Date
~~Additional 45-day Formal Comment Period with Parallel Ballot~~	~~May 2014~~
10-day Final Ballot	July 2014
BOT Approval	August 2014

Effective Dates

The standard, the revised definition of “Misoperation~~”~~,” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of “Misoperation~~”~~,” and the new definition of “Composite Protection System” shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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. Changed “Timeframe” to “Time Frame” in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC’s Order is effective as of September 26, 2011)	
2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add “…and generator interconnection Facility…”	Revision under Project 2010-07

2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	TBD	Adopted by Board of Trustees	Revision under Project 2010-05.1

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 *Glossary of Terms ~~used~~Used in NERC Reliability Standards* ("NERC Glossary") are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NERC Glossary.

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided ~~to~~by a ~~remote~~different Element's Protection System(s) is ~~included~~excluded.

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.

6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Protection System Misoperation Identification and Correction**

2. **Number:** PRC-004-3

3. **Purpose:** Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

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 for BES Elements, with the following exclusions:

4.2.1.1 Non-protective functions that are embedded within a Protection System.

4.2.1.2 Protective functions intended to operate as a control function during switching.[1]

4.2.1.3 Special Protection Systems (SPS).

4.2.1.4 Remedial Action Schemes (RAS).

4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

5. **Background**:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and

[1] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the ~~requirements~~Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition ~~needs~~needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also ~~includes~~included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed ~~requirements~~Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

6. Effective Dates:

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation ~~under the following circumstances~~: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This ~~requirement~~Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific ~~others~~other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which ~~that~~ backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that ~~when~~ Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.
In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or ~~hard copy~~hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following ~~development~~completion of each CAP, ~~development~~completion of each evaluation, and ~~development~~completion of each declaration.

The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

~~Periodic Data Submittal~~

1.4. Additional Compliance Information

None**.**

D. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

E. Regional Variances

None.

F. Interpretations

None.

G. Associated Documents

~~None.~~

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[2]

[2] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[3] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[4]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[5] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[6]." Misoperations of a Protection System include failure to operate, slowness in operating, or operating when not required either during a ~~fault~~Fault or non-~~fault~~Fault condition.

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[3] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[4] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011~~.~~. Pg. 3.

[5] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[6] "Transmission Protective Relay System Performance Measuring Methodology~~,"~~." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society~~,~~. 1999.

For reference, a "Protection System" is defined in the *Glossary of Terms ~~used~~Used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided ~~to~~by a ~~remote~~different Element's* Protection System*(s) is ~~included~~excluded*.

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** – *A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** – *A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*

3. ***Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a ~~fault~~Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended~~.~~ for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the ~~fault~~Fault condition being cleared by remote backup Protection System operation.

Example 1a: A failure of a transformer's Composite Protection System to operate for a transformer ~~fault~~Fault is a Misoperation.

Example 1b: A failure of a "primary" transformer relay (or any other component) to operate for a transformer ~~fault~~Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.

Example 1c: A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.

Example 1d: A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.

Example 1e: The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Example 2a: A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.

Example 2b: A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the ~~fault~~Fault is cleared.

Example ~~3~~3a: A ~~failure of a line's~~ Composite Protection System ~~to operate as quickly as intended~~that is slower than required for a ~~line fault~~Fault condition is a Misoperation~~.~~ if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line ~~fault~~Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

~~Installing high-speed protection may be a part of a utility's standard practice without having the need for high-speed protection to prevent voltage or dynamic instability or to maintain relay coordination. For this case, a "Slow Trip – During Fault" of the high-speed protection is not a Misoperation because it would not negatively impact the dynamic BES performance, unless the Composite Protection System operation is slower than previously identified as being necessary to~~

~~prevent voltage or dynamic instability. The Composite Protection System must also coordinate with other Protection Systems to prevent the trip (e.g., an over-trip) of additional Protection Systems.~~

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A ~~failure~~phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate~~ as quickly as intended for an overexcitation condition is~~. This was a Misoperation of the generator's Composite Protection System, but not of the transmission line's Composite Protection System.

The "Slow Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the ~~fault~~Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the ~~fault~~Fault. A BES interrupting device failure, a "failure to trip" Misoperation, or a "slow trip" Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line ~~fault~~Fault is a Misoperation. The ~~fault~~Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.

> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an "Unnecessary Trip – During Fault" Misoperation.

> **Example 5c:** If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-~~fault~~Fault conditions include but are not limited to~~,~~: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

> **Example 6a:** An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.
>
> **Example 6b:** Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.
>
> **Example 6c:** An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.
>
> **Example 6d:** Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-~~fault~~Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

> **Example 6e:** A BES interrupting device operation that occurs at the remote end of a line during a non-~~fault~~Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation~~.~~ because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

~~If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip," category of Misoperation at the remote terminal.~~

Special Cases

Protection System operations for these cases would not be a Misoperation.

> **Example 7a:** A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations ~~which~~that occur ~~with~~when the protected Element is out of service~~,~~ and that do not trip any in-service Elements~~,~~ are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

Example 7b: The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high~~-~~-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for ~~faults~~Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer ~~fault~~Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

Example7c: A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.~~ The operation trips only the capacitor bank breaker that was closed to energize the bank. Since closing the breaker put the capacitor bank into service, this is a Misoperation.~~

Example 7d: A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush ~~following a maintenance outage.~~after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed~~. Since closing the breaker put the transformer bank into service, this is a Misoperation~~.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

Example 8a: The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.

Example 8b: The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement ~~R1~~Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This ~~requirement~~Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case~~,~~ where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, ~~Requirement R2, Part 2.2 requires the entity that had~~ the BES interrupting device ~~operation to notify the other owner(s) to~~owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its ~~portion of Composite~~ Protection System component operated as backup protection for ~~Misoperation~~a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure~~, it~~. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation ~~until~~for a cause of the ~~entity determines otherwise~~Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether ~~or not a Misoperation of~~ its Protection System component(s) ~~occurred.~~ caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under ~~requirement~~Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC ~~SPCS guidance.~~*Misoperations Report*[7] which states:

~~Repeated Misoperations which occur during the same 24 hour period do not need a separate identification under requirement R1. This is consistent with NERC PSMTF guidance.~~

~~When Elements are isolated from the BES and undergoing maintenance, they are not subject to the standard, provided they do not result in the operation of any interrupting devices that are part of the BES.~~

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

[7] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This ~~requirement~~Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external ~~fault~~Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, ~~was required to notify~~notified the Generator Owner of the operation. The Generator Owner investigated ~~to determine if~~and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in ~~part~~Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the ~~GO~~Generator Owner and ~~TO~~Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure~~, it~~. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the ~~latter~~second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[8]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

The following are examples of a declaration where no cause was determined:

> **Example R4b**: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014~~.~~ as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

> **Example R4c:** A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must ~~create~~develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation~~;~~ ~~in~~. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple ~~CAPs~~CAP(s) to correct multiple causes of a Misoperation. The 60 calendar

[8] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf~~,~~. Figure 15: NERC Wide Misoperations by Cause Code~~,~~. pg. 22 of 40.

day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

~~The time periods within Requirement R1, R3 and R5 are distinct and separate. If a cause of a Misoperation is identified quickly, the time period in Requirement R1 or R3 ends and the 60 calendar day period to develop the CAP becomes applicable. The ultimate goal is to keep all time periods as short as possible, including the correction of the cause(s) of the Misoperation. See Requirement R6 for CAP implementation. Where there are multiple Protection System owners involved in a Misoperation, each owner whose Protection System component(s) contributed to the Misoperation is subject to Requirement R5.~~

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of ~~the CAPs~~each CAP in ~~examples~~Examples R5a through R5d, please see ~~examples~~Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.

Example R5h: As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase ~~fault~~Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this ~~fault~~Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

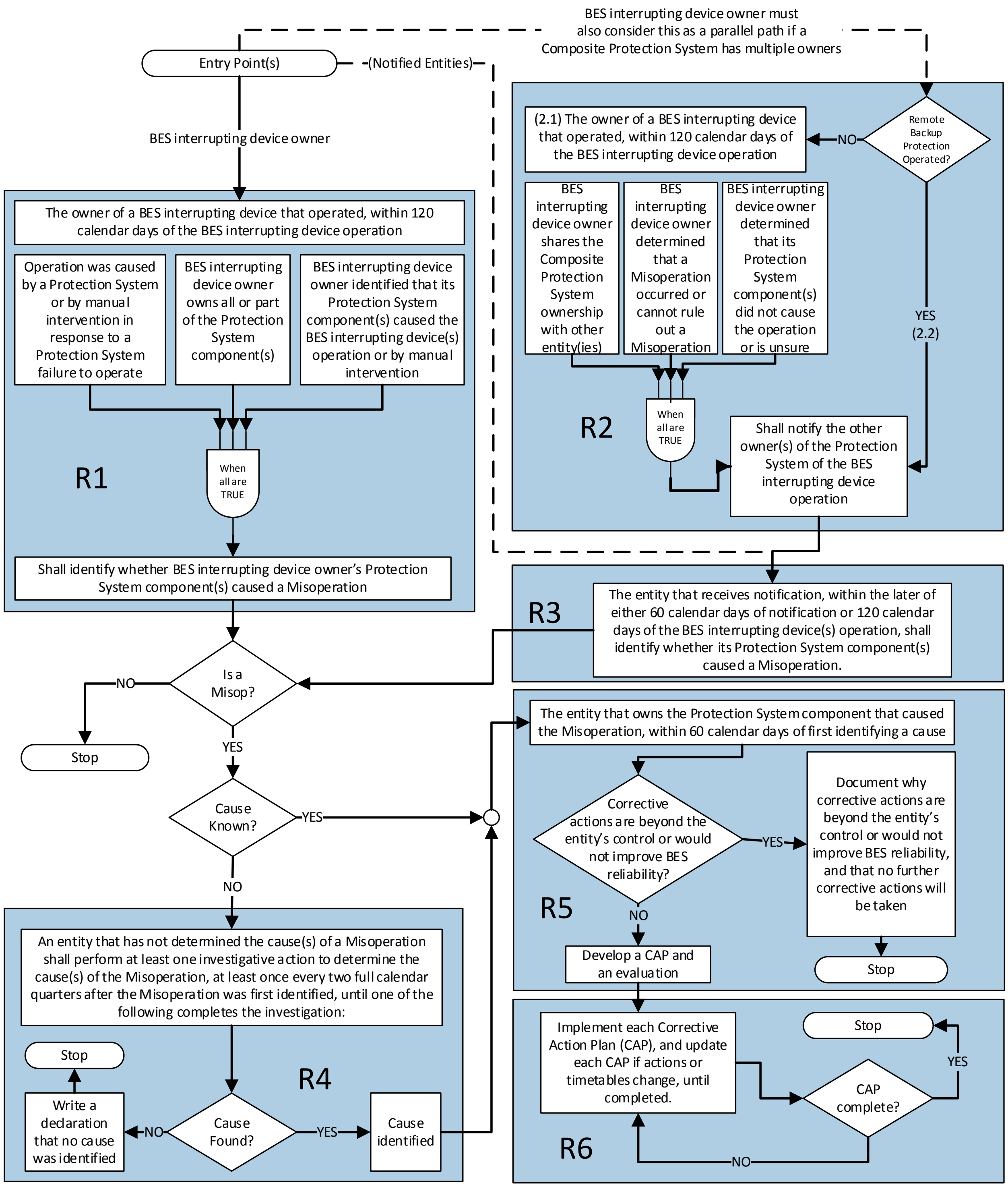
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between ~~requirements~~Requirements:



A. ~~Introduction~~

~~Title: Analysis~~ Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and ~~**Mitigation of Transmission**~~ *will be removed when the standard becomes effective.*

Development Steps Completed

1. The SC authorized moving the SAR forward for standard development at their June 9, 2011 meeting.
2. The SAR was posted for informal comment June 10 – July 11, 2011.
3. Draft 1 of PRC-004-3 was posted for a 30-day formal comment period from June 10 – July 11, 2011.
4. Draft 2 of PRC-004-3 was posted for a 45-day formal comment period from July 25 – September 7, 2012 and ~~Generation~~an initial ballot in the last ten days of the comment period from August 29 – September 7, 2012.
5. Draft 3 of PRC-004-3 was posted for a 30-day formal comment period from January 22 – February 20, 2013 and a successive ballot in the last ten days of the comment period from February 11-20, 2013.
6. Draft 4 of PRC-004-3 was posted for a 45-day additional comment period from January 17 – March 11, 2014 and an additional ballot in the last ten days of the comment period from February 2 – March 11, 2014 under the new Standards Process Manual (Effective: June 26, 2013).
7. Draft 5 of PRC-004-3 was posted for a 45-day additional comment period from May 16 – July 9, 2014 and an additional ballot in the last ten days of the comment period from June 20 – July 9, 2014.

Description of Current Draft

The Protection System Misoperations Standard Drafting Team (PSMSDT) is posting Draft 6 of PRC-004-3 – Protection System Misoperation Identification and Correction for a 10-day final ballot.

~~**1. Number:** PRC-004-2.1a~~

~~**2. Purpose:** Ensure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.~~

~~**3. Applicability**~~

~~**3.1.** Transmission Owner.~~

~~**3.2.** Distribution Provider that owns a transmission Protection System.~~

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~~**3.3.** Generator Owner.~~

~~**4.** **(Proposed) Effective Date:** In those jurisdictions where regulatory approval is required, all requirements become effective upon approval. In those jurisdictions where no regulatory approval is required, all requirements become effective upon Board of Trustees' adoption.~~

~~A. Requirements~~

~~**R1.** The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.~~

~~**R2.** The Generator Owner shall analyze its generator and generator interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.~~

~~**R3.** The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.~~

~~B. Measures~~

~~**M1.** The Transmission Owner, and any Distribution Provider that owns a transmission Protection System shall each have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.~~

~~**M2.** The Generator Owner shall have evidence it analyzed its Protection System Misoperations and developed and implemented Corrective Action Plans to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.~~

~~**M3.** Each Transmission Owner, and any Distribution Provider that owns a transmission Protection System, and each Generator Owner shall have evidence it provided documentation of its Protection System Misoperations, analyses and Corrective Action Plans according to the Regional Entity's procedures.~~

B. ~~Compliance~~

1. ~~Compliance Monitoring Process~~

1.1. ~~Compliance Enforcement Authority~~

~~Regional Entity.~~

~~1.2. Compliance Monitoring Period and Reset Time Frame~~

~~Not applicable.~~

~~1.3. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.4. Data Retention~~

~~The Transmission Owner, and Distribution Provider that own a transmission Protection System and the Generator Owner that owns a generation or generator interconnection Facility Protection System shall each retain data on its Protection System Misoperations and each accompanying Corrective Action Plan until the Corrective Action Plan has been executed or for 12 months, whichever is later.~~

~~The Compliance Monitor shall retain any audit data for three years.~~

~~1.5.~~1.2. ~~Additional Compliance Information~~

~~The Transmission Owner, and any Distribution Provider that owns a transmission Protection System and the Generator Owner shall demonstrate compliance through self- certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.~~

~~2. Violation Severity Levels (no changes)~~

~~C. Regional Differences~~

~~None identified.~~

Anticipated Actions	Anticipated Date
10-day Final Ballot	July 2014
BOT Approval	August 2014

Effective Dates

The standard, the revised definition of "Misoperation," and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of "Misoperation," and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

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. Changed "Timeframe" to "Time Frame" in item D, 1.2.	01/20/06
2		Modified to address Order No. 693 Directives contained in paragraph 1469.	Revised
2	August 5, 2010	Adopted by NERC Board of Trustees	
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 the Board of Trustees	
1a	September 26, 2011	FERC Order issued approving the interpretation of R1 and R3 (FERC's Order is effective as of September 26, 2011)	

—2a	September 26, 2011	Appended FERC-approved interpretation of R1 and R3 to version 2	
2.1a		Errata change: Edited R2 to add "…and generator interconnection Facility…"	Revision under Project 2010-07
2.1a	February 9, 2012	Errata change adopted by the Board of Trustees	
2.1a	September 19, 2013	FERC Order issued approving PRC-004-2.1a (approval becomes effective November 25, 2013).	
3	TBD	Adopted by Board of Trustees	Revision under Project 2010-05.1

~~Appendix 1~~[1]

~~**Requirement Number and Text of Requirement**~~
~~**R1.** The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Reliability Organization's procedures developed for Reliability Standard PRC-003 Requirement 1.~~ ~~**R3**. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Reliability Organization, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Reliability Organization's procedures developed for PRC-003 R1.~~
~~**Question:**~~
~~Is protection for a radially-connected transformer protection system energized from the BES considered a transmission Protection System subject to this standard?~~
~~**Response:**~~
~~The request for interpretation of PRC-004-1 Requirements R1 and R3 focuses on the applicability of the term "transmission Protection System." The NERC Glossary of Terms Used in Reliability Standards contains a definition of "Protection System" but does not contain a definition of transmission Protection System. In these two standards, use of the phrase transmission Protection System indicates that the requirements using this phrase are applicable to any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES.~~ ~~A Protection System for a radially connected transformer energized from the BES would be considered a transmission Protection System and subject to these standards only if the protection trips an interrupting device that interrupts current supplied directly from the BES and the transformer is a BES element.~~

~~[1] When the request for interpretation was made, it was for a previous version of the standard. Although the interpretation references a previous version of the standard, because it is still applicable in this case, it is appended to this version of the standard.~~

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 *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the NERC Glossary.

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.

When this standard has received ballot approval, the rationale boxes will be moved to the Application Guidelines Section of the Standard.

C. Introduction

2. Title: **Protection System Misoperation Identification and Correction**

3. Number: PRC-004-3

4. Purpose: Identify and correct the causes of Misoperations of Protection Systems for Bulk Electric System (BES) Elements.

5. Applicability:

5.1. Functional Entities:

5.1.1 Transmission Owner

5.1.2 Generator Owner

5.1.3 Distribution Provider

5.2. Facilities:

5.2.1 Protection Systems for BES Elements, with the following exclusions:

5.2.1.1 Non-protective functions that are embedded within a Protection System.

5.2.1.2 Protective functions intended to operate as a control function during switching.[2]

5.2.1.3 Special Protection Systems (SPS).

5.2.1.4 Remedial Action Schemes (RAS).

5.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Rationale for Applicability: Protection Systems that protect BES Elements are integral to the operation and reliability of the BES. Some functions of relays are not used as protection but as control functions or for automation; therefore, any operation of the control function portion or the automation portion of relays is excluded from this standard. See the Application Guidelines for detailed examples of non-protective functions. Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded in this standard because they are planned to be handled in the second phase of this project.

[2] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

6. Background:

A key factor for BES reliability is the correct performance of Protection Systems. The monitoring of Protection System events for BES Elements, as well as identifying and correcting the causes of Misoperations, will improve Protection System performance. This Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In the FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the Requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3 combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

This project includes revising the existing definition of Misoperation, which reads:

Misoperation

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

In general, this definition needed more specificity and clarity. The terms "specified time" and "abnormal condition" are ambiguous. In the third bullet, more clarification is needed as to whether an unintentional Protection System operation for an atypical, yet explainable, condition is a Misoperation.

The SAR for this project also included clarifying reporting requirements. Misoperation data, as currently collected and reported, is not optimal to establish consistent metrics for measuring Protection System performance. As such, the data reporting obligation for this standard is being removed and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information ("data request"). As a result of the data request, NERC will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify remediation techniques; and publicize lessons learned for the industry. The removal of the data collection obligation from the standard does not result in a reduction of reliability. The standard and data request have been developed in a manner such that evidence used for compliance with the standard and data request are intended to be independent of each other.

The proposed Requirements of the revised Reliability Standard PRC-004-3 meet the following objectives:

- Review all Protection System operations on the BES to identify those that are Misoperations of Protection Systems for Facilities that are part of the BES.
- Analyze Misoperations of Protection Systems for Facilities that are part of the BES to identify the cause(s).
- Develop and implement Corrective Action Plans to address the cause(s) of Misoperations of Protection Systems for Facilities that are part of the BES.

Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities. NERC plans to handle SPS and RAS in the second phase of this project.

The Western Electric Coordinating Council (WECC) Regional Reliability Standard PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation relates to the reporting of Misoperations of Protection Systems and RAS for a limited set of WECC Paths. The WECC region plans to conduct work to harmonize the regional standard with this continent-wide proposed standard and the second phase of this project concerning SPS and RAS.

Undervoltage load shedding (UVLS) has not been included in this standard's applicability because Misoperations of UVLS relays are currently addressed by Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance, Requirement R1.5. Underfrequency load shedding (UFLS) was added to PRC-004-3 to close a gap in reliability as Misoperations of UFLS relays are not covered by a Reliability Standard currently.

7. Effective Dates:

The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months 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 that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

D. Requirements and Measures

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

1.1 The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and

1.2 The BES interrupting device owner owns all or part of the Composite Protection System; and

1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement R1, Parts 1.1, 1.2, and 1.3 within the allotted time period. Acceptable evidence for Requirement R1, including Parts 1.1, 1.2, and 1.3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R1: This Requirement ensures that entities review those Protection System operations meeting the circumstances in all three Parts (1.1, 1.2, and 1.3) and identify any that are Misoperations. The BES interrupting device owner is assigned the responsibility to initiate the review because the owner is in the best position to be aware of the operation. Manual intervention is included as a condition that initiates a review. Occasionally, Protection System failures do not yield other Protection System operations and manual intervention is required to isolate the problematic equipment. The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in Parts 2.1 and 2.2. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

2.1 For a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances:

2.1.1 The BES interrupting device owner shares the Composite Protection System ownership with any other owner; and

2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.1.3 The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation.

2.2 For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided.

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates notification to the other owner(s), within the allotted time period for either Requirement R2, Part 2.1, including subparts 2.1.1, 2.1.2, and 2.1.3 and Requirement R2, Part 2.2. Acceptable evidence for Requirement R2, including Parts 2.1 and 2.2 may include, but is not limited to the following dated documentation (electronic or hardcopy format): emails, facsimiles, or transmittals.

Rationale for R2: Part 2.1 ensures that the BES interrupting device owner notifies the other owners of the Composite Protection System. The phrase "owner(s) that share Misoperation identification responsibility" allows entities to notify the specific other owners that will actually review the operation to determine if a Misoperation occurred. Part 2.2 ensures that the Protection System owner(s) for which backup protection was provided receives notification, within the same 120 calendar day period as R1. This ensures other entities are notified to review their Protection System components. The expectation is that entities will communicate accordingly and when it is clear that Part 2.1, 2.2, or both are met, the entity would make the notification. It is not intended for entities to automatically and unnecessarily notify other entities before adequate detail is known.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. *[Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]*

M3. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it identified whether its Protection System component(s) caused a Misoperation within the allotted time period. Acceptable evidence for Requirement R3 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R3: When an entity receives notification of a Protection System operation by the BES interrupting device owner, the other Protection System owner is allotted at least 60 calendar days to identify whether it was a Misoperation. A shorter time period is allotted on the basis that the BES interrupting device owner has already performed preliminary work, collaborated with the other owners, and that other owners generally have fewer associated Protection System components.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment, Operations Planning]*

- The identification of the cause(s) of the Misoperation; or
- A declaration that no cause was identified.

M4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it performed at least one investigative action according to Requirement R4 every two full calendar quarters until a cause is identified or a declaration is made. Acceptable evidence for Requirement R4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Monitoring Equipment (DME) records, test results, or transmittals.

Rationale for R4: If a Misoperation cause is not identified within the time period established by Requirements R1 or R3 (i.e., 120 calendar days), the Protection System component owner must demonstrate investigative actions toward identifying the cause(s). Performing at least one action every two full calendar quarters from first identifying the Misoperation encourages periodic focus on finding the cause of the Misoperation.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning, Long-Term Planning*]

- Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations; or
- Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken.

M5. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement R5. Acceptable evidence for Requirement R5 may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.

Rationale for R5: A formal CAP is a proven tool for resolving and reducing the possibility of reoccurrence of operational problems. A time period of 60 calendar days is based on industry experience and operational coordination time needed for considering such things as alternative solutions, coordination of resources, or development of a schedule. When the cause of a Misoperation is identified, a CAP will generally be developed. An evaluation of the CAP's applicability to the entity's other Protection Systems including other locations helps identify similar problems, the potential for Misoperation occurrences in other Protection Systems, common mode failure, design problems, etc.

In rare cases, altering the Protection System to avoid a Misoperation recurrence may lower the reliability or performance of the BES. In those cases, a statement documenting the reasons for taking no corrective actions is essential for future reference and for justifying the absence of a CAP.

R6. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. *[Violation Risk Factor: Medium][Time Horizon: Operations Planning, Long-Term Planning]*

M6. Each Transmission Owner, Generator Owner, and Distribution Provider shall have dated evidence that demonstrates it implemented each CAP, including updating actions or timetables. Acceptable evidence for Requirement R6 may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.

Rationale for R6: Each CAP must accomplish all identified objectives to be complete. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion.

~~D.~~E. Compliance

~~3.~~8. Compliance Monitoring Process

~~3.1.~~8.1. Compliance Enforcement Authority

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

8.2. 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 CEA 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 keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirements R1, R2, R3, and R4, Measures M1, M2, M3, and M4 for a minimum of 12 calendar months following the completion of each Requirement.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R5, Measure M5, including any supporting analysis per Requirements R1, R2, R3, and R4, for a minimum of 12 calendar months following completion of each CAP, completion of each evaluation, and completion of each declaration.
>
> The Transmission Owner, Generator Owner, and Distribution Provider shall retain evidence of Requirement R6, Measure M6 for a minimum of 12 calendar months following completion of each CAP.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

~~3.2.~~8.4. Additional Compliance Information

None.

F. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment, Operations Planning	Medium	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Assessment, Operations Planning	Medium	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Assessment, Operations Planning	Medium	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	Operations Planning, Long-Term Planning	Medium	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR (See next page)	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR (See next page)

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	(Continued)		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
R6	Operations Planning, Long-Term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

G. Regional Variances

None.

H. Interpretations

None.

I. Associated Documents

NERC System Protection and Controls Subcommittee of the NERC Planning Committee, Assessment of Standards: PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, PRC-004-1 – Analysis and Mitigation of Transmission and Generation Protection Misoperations, PRC-016-1 – Special Protection System Misoperations, May 22, 2009.[3]

[3] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%20DL/PRC-003-004-016%20Report.pdf

Guidelines and Technical Basis

Introduction

This standard addresses the reliability issues identified in the letter[4] from Gerry Cauley, NERC President and CEO, dated January 7, 2011.

> "Nearly all major system failures, excluding perhaps those caused by severe weather, have misoperations of relays or automatic controls as a factor contributing to the propagation of the failure. …Relays can misoperate, either operate when not needed or fail to operate when needed, for a number of reasons. First, the device could experience an internal failure – but this is rare. Most commonly, relays fail to operate correctly due to incorrect settings, improper coordination (of timing and set points) with other devices, ineffective maintenance and testing, or failure of communications channels or power supplies. Preventable errors can be introduced by field personnel and their supervisors or more programmatically by the organization."

The standard also addresses the findings in the *2011 Risk Assessment of Reliability Performance*[5]; July 2011.

> "…a number of multiple outage events were initiated by protection system Misoperations. These events, which go beyond their design expectations and operating procedures, represent a tangible threat to reliability. A deeper review of the root causes of dependent and common mode events, which include three or more automatic outages, is a high priority for NERC and the industry."

The *State of Reliability 2014*[6] report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Definitions

The Misoperation definition is based on the IEEE/PSRC Working Group I3 "Transmission Protective Relay System Performance Measuring Methodology[7]." Misoperations of a Protection

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[4] http://www.nerc.com/pa/Stand/Project%20201005%20Protection%20System%20Misoperations%20DL/20110209130708-Cauley%20letter.pdf

[5] "2011 Risk Assessment of Reliability Performance." NERC. http://www.nerc.com/files/2011_RARPR_FINAL.pdf. July 2011. Pg. 3.

[6] "State of Reliability 2014." NERC. http://www.nerc.com/pa/Stand/Pages/RelaibilityCoordinationProject20066.aspx. May 2014. Pg. 18 of 106.

[7] "Transmission Protective Relay System Performance Measuring Methodology." Working Group I3 of Power System Relaying Committee of IEEE Power Engineering Society. 1999.

System include failure to operate, slowness in operating, or operating when not required either during a Fault or non-Fault condition.

For reference, a "Protection System" is defined in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") as:

- 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.

A BES interrupting device is a BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current. Although BES interrupting device mechanisms are not part of a Protection System, the standard uses the operation of a BES interrupting device by a Protection System to initiate the review for Misoperation.

The following two definitions are being proposed for inclusion in the NERC Glossary:

> **Composite Protection System –** *The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.*

The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Composite Protection System – Line Example

The Composite Protection System of the Alpha-Beta line (Circuit #123) is comprised of current differential, permissive overreaching transfer trip (POTT), step distance (classic zone 1, zone 2, and zone 3), instantaneous-overcurrent, time-overcurrent, out-of-step, and overvoltage protection. The protection is housed at the Alpha and Beta substations, and includes the associated relays, communications systems, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Transformer Example

The Composite Protection System of the Alpha transformer (#2) is comprised of internal differential, overall differential, instantaneous-overcurrent, and time-overcurrent protection. The protection is housed at the Alpha substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Generator Example

The Composite Protection System of the Beta generator (#3) is comprised of generator differential, overall differential, overcurrent, stator ground, reverse power, volts per hertz, loss-of-field, and undervoltage protection. The protection is housed at the Beta generating plant and at the Beta substation, and includes the associated relays, voltage and current sensing devices, DC supplies, and control circuitry.

Composite Protection System – Breaker Failure Example

Breaker failure protection provides backup protection for the breaker, and therefore is part of the breaker's Composite Protection System. Considering breaker failure protection to be part of another Element's Composite Protection System could lead to an incorrect conclusion that a breaker failure operation automatically satisfies the "Slow Trip" criteria of the Misoperation definition.

- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. The breaker failure relaying operated because of a failed trip coil. The failed trip coil caused a Misoperation of the line's Composite Protection System.
- An example of a correct operation of the breaker's Composite Protection System is when the breaker failure relaying tripped because the line relaying operated, but the breaker failed to clear the Fault. Only the breaker failure relaying operated because of a failed breaker mechanism. This was not a Misoperation because the breaker mechanism is not part of the breaker's Composite Protection System.
- An example of an "Unnecessary Trip – During Fault" is when the breaker failure relaying tripped at the same time as the line relaying during a Fault. The Misoperation was due to the breaker failure timer being set to zero.

Misoperation – *The failure a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:*

1. **Failure to Trip – During Fault** *– A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
2. ***Failure to Trip – Other Than Fault*** *– A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.*
3. ***Slow Trip – During Fault*** *– A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
4. ***Slow Trip – Other Than Fault*** *– A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation, if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.*
5. ***Unnecessary Trip – During Fault*** *– An unnecessary Composite Protection System operation for a Fault condition on another Element.*
6. ***Unnecessary Trip – Other Than Fault*** *– An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction, or commissioning activities is not a Misoperation.*

The Misoperation definition is based on the principle that an Element's total complement of protection is intended to operate dependably and securely.

- Failure to automatically reclose after a Fault condition is not included as a Misoperation because reclosing equipment is not included within the definition of Protection System.
- A breaker failure operation does not, in itself, constitute a Misoperation.
- A remote backup operation resulting from a "Failure to Trip" or a "Slow Trip" does not, in itself, constitute a Misoperation.

This proposed definition of Misoperation provides additional clarity over the current version. A Misoperation is the failure of a Composite Protection System to operate as intended for protection purposes. The definition includes six categories which provide further differentiation of what constitutes a Misoperation. These categories are discussed in greater detail in the following sections.

Failure to Trip – During Fault

This category of Misoperation typically results in the Fault condition being cleared by remote backup Protection System operation.

> **Example 1a:** A failure of a transformer's Composite Protection System to operate for a transformer Fault is a Misoperation.
>
> **Example 1b:** A failure of a "primary" transformer relay (or any other component) to operate for a transformer Fault is not a "Failure to Trip – During Fault" Misoperation as long as another component of the transformer's Composite Protection System operated.
>
> **Example 1c:** A lack of target information does not by itself constitute a Misoperation. When a high-speed pilot system does not target because a high-speed zone element trips first, it would not in and of itself be a Misoperation.
>
> **Example 1d:** A failure of an overall differential relay to operate is not a "Failure to Trip – During Fault" Misoperation as long as another component such as a generator differential relay operated.
>
> **Example 1e:** The Composite Protection System for a bus does not operate during a bus Fault which results in the operation of all local transformer Protection Systems connected to that bus and all remote line Protection Systems connected to that bus isolating the faulted bus from the grid. The operation of the local transformer Protection Systems and the operation of all remote line Protection Systems correctly provided backup protection. There is one "Failure to Trip – During Fault" Misoperation of the bus Composite Protection System.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – During Fault" category applies to the operation.

Failure to Trip – Other Than Fault

This category of Misoperation may have resulted in operator intervention. The "Failure to Trip – Other Than Fault" conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

> **Example 2a:** A failure of a generator's Composite Protection System to operate for an unintentional loss of field condition is a Misoperation.
>
> **Example 2b:** A failure of an overexcitation relay (or any other component) is not a "Failure to Trip – Other Than Fault" Misoperation as long as the generator's Composite Protection System operated as intended isolating the generator from the BES.

In analyzing the Protection System for Misoperation, the entity must also consider whether the "Slow Trip – Other Than Fault" category applies to the operation.

Slow Trip – During Fault

This category of Misoperation typically results in remote backup Protection System operation before the Fault is cleared.

> **Example 3a:** A Composite Protection System that is slower than required for a Fault condition is a Misoperation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. The current differential element of a multiple function relay failed to operate for a line Fault. The same relay's time-overcurrent element operated after a time delay. However, an adjacent line also operated from a time-overcurrent element. The faulted line's time-overcurrent element was found to be set to trip too slowly.

> **Example 3b:** A failure of a breaker's Composite Protection System to operate as quickly as intended to meet the expected critical Fault clearing time for a line Fault in conjunction with a breaker failure (i.e., stuck breaker) is a Misoperation if it resulted in an unintended operation of at least one other Element's Composite Protection System. If a generating unit's Composite Protection System operates due to instability caused by the slow trip of the breaker's Composite Protection System, it is not an "Unnecessary Trip – During Fault" Misoperation of the generating unit's Composite Protection System. This event would be a "Slow Trip – During Fault" Misoperation of the breaker's Composite Protection System.

> **Example 3c:** A line connected to a generation interconnection station is protected with two independent high-speed pilot systems. The Composite Protection System for this line also includes step distance and time-overcurrent schemes in addition to the two pilot systems. During a Fault on this line, the two pilot systems fail to operate and the time-overcurrent scheme operates clearing the Fault with no generating units or other Elements tripping (i.e., no over-trips). This event is not a Misoperation.

The phrase "slower than required" means the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

The phrase "resulted in the operation of any other Composite Protection System" refers to the need to ensure that relaying operates in the proper or planned sequence (i.e., the primary relaying for a faulted Element operates before the remote backup relaying for the faulted Element).

In analyzing the Protection System for Misoperation, the entity must also consider the "Unnecessary Trip – During Fault" category to determine if an "unnecessary trip" applies to the Protection System operation of an Element other than the faulted Element.

If a coordination error was at the local terminal (i.e., set too slow), then it was a "Slow Trip," category of Misoperation at the local terminal.

Slow Trip – Other Than Fault

The phrase “slower than required” means the duration of its operating time resulted in the operation of at least one other Element’s Composite Protection System. It would be impractical to provide a precise tolerance in the definition that would be applicable to every type of Protection System. Rather, the owner(s) reviewing each Protection System operation should understand whether the speed and outcome of its Protection System operation met their objective. The intent is not to require documentation of exact Protection System operation times, but to assure consideration of relay coordination and system stability by the owner(s) reviewing each Protection System operation.

> **Example 4:** A phase to phase fault occurred on the terminals of a generator. The generator's Composite Protection System and a transmission line's Composite Protection System both operated in response to the fault. It was found during subsequent investigation that the generator protection contained an inappropriate time delay. This caused the transmission line's correctly set overreaching zone of protection to operate. This was a Misoperation of the generator’s Composite Protection System, but not of the transmission line’s Composite Protection System.

The “Slow Trip – Other Than Fault” conditions cited in the definition are examples only, and do not constitute an all-inclusive list.

Unnecessary Trip – During Fault

An operation of a properly coordinated remote Protection System is not in and of itself a Misoperation if the Fault has persisted for a sufficient time to allow the correct operation of the Composite Protection System of the faulted Element to clear the Fault. A BES interrupting device failure, a “failure to trip” Misoperation, or a “slow trip” Misoperation may result in a proper remote Protection System operation.

> **Example 5:** An operation of a transformer's Composite Protection System which trips (i.e., over-trips) for a properly cleared line Fault is a Misoperation. The Fault is cleared properly by the faulted equipment's Composite Protection System (i.e., line relaying) without the need for an external Protection System operation resulting in an unnecessary trip of the transformer protection; therefore, the transformer Protection System operation is a Misoperation.
>
> **Example 5b:** An operation of a line's Composite Protection System which trips (i.e., over-trips) for a properly cleared Fault on a different line is a Misoperation. The Fault is cleared properly by the faulted line's Composite Protection System (i.e., line relaying); however, elsewhere in the system, a carrier blocking signal is not transmitted (e.g., carrier ON/OFF switch found in OFF position) resulting in the operation of a remote Protection System, single-end trip of a non-faulted line. The operation of the Protection System for the non-faulted line is an unnecessary trip during a Fault. Therefore, the non-faulted line Protection System operation is an “Unnecessary Trip – During Fault” Misoperation.

Example 5c: If a coordination error was at the remote terminal (i.e., set too fast), then it was an "Unnecessary Trip – During Fault" category of Misoperation at the remote terminal.

Unnecessary Trip – Other Than Fault

Unnecessary trips for non-Fault conditions include but are not limited to: power swings, overexcitation, loss of excitation, frequency excursions, and normal operations.

Example 6a: An operation of a line's Composite Protection System due to a relay failure during normal operation is a Misoperation.

Example 6b: Tripping a generator by the operation of the loss of field protection during an off-nominal frequency condition while the field is intact is a Misoperation assuming the Composite Protection System was not intended to operate under this condition.

Example 6c: An impedance line relay trip for a power swing that entered the relay's characteristic is a Misoperation if the power swing was stable and the relay operated because power swing blocking was enabled and should have prevented the trip, but did not.

Example 6d: Tripping a generator operating at normal load by the operation of a reverse power protection relay due to a relay failure is a Misoperation.

Additionally, an operation that occurs during a non-Fault condition but was initiated directly by on-site (i.e., real-time) maintenance, testing, inspection, construction, or commissioning is not a Misoperation.

Example 6e: A BES interrupting device operation that occurs at the remote end of a line during a non-Fault condition because a direct transfer trip was initiated by system maintenance and testing activities at the local end of the line is not a Misoperation because of the maintenance exclusion in category 6 of the definition of "Misoperation."

The "on-site" activities at one location that initiates a trip to another location are included in this exemption. This includes operation of a Protection System when energizing equipment to facilitate measurements, such as verification of current circuits as a part of performing commissioning; however, once the maintenance, testing, inspection, construction, or commissioning activity associated with the Protection System is complete, the "on-site" Misoperation exclusion no longer applies, regardless of the presence of on-site personnel.

Special Cases

Protection System operations for these cases would not be a Misoperation.

Example 7a: A generator Protection System operation prior to closing the unit breaker(s) is not a Misoperation provided no in-service Elements are tripped.

This type of operation is not a Misoperation because the generating unit is not synchronized and is isolated from the BES. Protection System operations that occur when the protected Element is out of service and that do not trip any in-service Elements are not Misoperations.

In some cases where zones of protection overlap, the owner(s) of Elements may decide to allow a Protection System to operate faster in order to gain better overall Protection System performance for an Element.

> **Example 7b:** The high-side of a transformer connected to a line may be within the zone of protection of the supplying line's relaying. In this case, the line relaying is planned to protect the area of the high-side of the transformer and into its primary winding. In order to provide faster protection for the line, the line relaying may be designed and set to operate without direct coordination (or coordination is waived) with local protection for Faults on the high-side of the connected transformer. Therefore, the operation of the line relaying for a high-side transformer Fault operated as intended and would not be a Misoperation.

Below are examples of conditions that would be a Misoperation.

> **Example7c:** A 230 kV shunt capacitor bank was released for operational service. The capacitor bank trips due to a settings error in the capacitor bank differential relay upon energization.
>
> **Example 7d:** A 230/115 kV BES transformer bank trips out when being re-energized due to an incorrect operation of the transformer differential relay for inrush after being released for operational service. Only the high-side breaker opens since the low-side breaker had not yet been closed.

Non-Protective Functions

BES interrupting device operations which are initiated by non-protective functions, such as those associated with generator controls, excitation controls, or turbine/boiler controls, static voltampere-reactive compensators (SVC), flexible ac transmission systems (FACTS), high-voltage dc (HVdc) transmission systems, circuit breaker mechanisms, or other facility control systems are not operations of a Protection System. The standard is not applicable to non-protective functions such as automation (e.g., data collection) or control functions that are embedded within a Protection System.

Control Functions

The entity must make a determination as to whether the standard is applicable to each operation of its Protection System in accordance with the provided exclusions in the standard's Applicability, see Section 4.2.1. The subject matter experts (SME) developing this standard recognize that entities use Protection Systems as part of a routine practice to control BES Elements. This standard is not applicable to operation of protective functions within a Protection System when intended for controlling a BES Element as a part of an entity's process or planned switching sequence. The following are examples of conditions to which this standard is not applicable:

> **Example 8a:** The reverse power protective function that operates to remove a generating unit from service using the entity's normal or routine process.
>
> **Example 8b:** The reverse power relay enables a permissive trip and the generator operator trips the unit.

The standard is not applicable to operation of the protective relay because its operation is intended as a control function as part of a controlled shutdown sequence for the generator. However, the standard remains applicable to operation of the reverse power relay when it operates for conditions not associated with the controlled shutdown sequence, such as a motoring condition caused by a trip of the prime mover.

The following is another example of a condition to which this standard is not applicable:

> **Example 8c:** Operation of a capacitor bank interrupting device for voltage control using functions embedded within a microprocessor based relay that is part of a Protection System.

The above are examples only, and do not constitute an all-inclusive list to which the standard is not applicable.

Extenuating Circumstances

In the event of a natural disaster or other extenuating circumstances, the December 20, 2012 Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, reads: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." The Regional Entities to whom NERC has delegated authority will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard.

The volume of Protection System operations tend to be sporadic. If a high rate of Protection System operations is not sustained, utilities will have an opportunity to catch up within the 120 day period.

Requirement Time Periods

The time periods within all the Requirements are distinct and separate. The applicable entity in Requirement R1 has 120 calendar days to identify whether a BES interrupting device operation is a Misoperation. Once the applicable entity has identified a Misoperation, it has completed its performance under Requirement R1. Identified Misoperations without an identified cause become subject to Requirement R4 and any subsequent Requirements as necessary. Identified Misoperations with an identified cause become subject to Requirement R5 and any subsequent Requirements as necessary.

In Requirement R2, the applicable entity has 120 calendar days, based on the date of the BES interrupting device operation, to provide notification to the other Protection System owners that meet the circumstances in Parts 2.1 and 2.2. For the case of an applicable entity that was notified (R3), it has the later of 120 calendar days from the date of the BES interrupting device operation or 60 calendar days of notification to identify whether its Protection System components caused a Misoperation.

Once a Misoperation is identified in either Requirement R1 or R3, and the applicable entity did not identify the cause(s) of the Misoperation, the time period for performing at least one investigative action every two full calendar quarters begins. The time period(s) in Requirement R4 resets upon each period. When the applicable entity's investigative actions identify the cause of the identified Misoperation or the applicable entity declares that no cause was found, the applicable entity has completed its performance in Requirement R4.

The time period in Requirement R5 begins when the Misoperation cause is first identified. The applicable entity is allotted 60 calendar days to perform one of the two activities listed in Requirement R5 (e.g., CAP or declaration) to complete its performance under Requirement R5.

Requirement R6 time period is determined by the actions and the associated timetable to complete those actions identified in the CAP. The time periods contained in the CAP may change from time to time and the applicable entity is required to update the timetable when it changes.

Time periods provided in the Requirements are intended to provide a reasonable amount of time to perform each Requirement. Performing activities in the least amount of time facilitates prompt identification of Misoperations, notification to other Protection System owners, identification of the cause(s), correction of the cause(s), and that important information is retained that may be lost due to time.

Requirement R1

This Requirement initiates a review of each BES interrupting device operation to identify whether or not a Misoperation may have occurred. Since the BES interrupting device owner typically monitors and tracks device operations, the owner is the logical starting point for identifying Misoperations of Protection Systems for BES Elements. A review is required when (1) a BES interrupting device operates that is caused by a Protection System or by manual intervention in response to a Protection System failure to operate, (2) regardless of whether the owner owns all or part of the Protection System component(s), and (3) the owner identified its Protection System component(s) as causing the BES interrupting device operation or was caused by manual intervention in response to its Protection System failure to operate.

Since most Misoperations result in the operation of one or more BES interrupting devices, these operations initiate a review to identify any Misoperation. If an Element is manually isolated in response to a failure to operate, the manual isolation of the Element triggers a review for Misoperation.

> **Example R1a:** The failure of a loss of field relay on a generating unit where an operator takes action to isolate the unit.

Manual intervention may indicate a Misoperation has occurred, thus requiring the initiation of an investigation by the BES interrupting device owner.

For the case where a BES interrupting device did not operate and remote clearing occurs due to the failure of a Composite Protection System to operate, the BES interrupting device owner would still review the operation under Requirement R1. However, if the BES interrupting device owner determines that its Protection System component operated as backup protection for a condition on another entity's BES Element, the owner would provide notification of the operation to the other Protection System owner(s) under Requirement R2, Part 2.2.

Protection Systems are made of many components. These components may be owned by different entities. For example, a Generator Owner may own a current transformer that sends information to a Transmission Owner's differential relay. All of these components and many more are part of a Protection System. It is expected that all of the owners will communicate with each other, sharing information freely, so that Protection System operations can be analyzed, Misoperations identified, and corrective actions taken.

Each entity is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation regardless of the level of ownership. A combination of available information from resources such as counters, relay targets, Supervisory Control and Data Acquisition (SCADA) systems, or Disturbance Monitoring Equipment (DME) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation. The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether its Protection System component(s) caused a Misoperation.

The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System.

Repeated operations which occur during the same automatic reclosing sequence do not need a separate identification under Requirement R1. Repeated Misoperations which occur during the same 24-hour period do not need a separate identification under Requirement R1. This is consistent with the NERC *Misoperations Report*[8] which states:

> "In order to avoid skewing the data with these repeated events, the NERC SPCS should clarify, in the next annual update of the misoperation template, that all misoperations due to the same equipment and cause within a 24 hour period be recorded as one misoperation."

The following is an example of a condition that is not a Misoperation.

> **Example R1b:** A high impedance Fault occurs within a transformer. The sudden pressure relaying detects and operates for the Fault, but the differential relaying did not operate due to the low Fault current levels. This is not a Misoperation because the Composite Protection System was not required to operate because the Fault was cleared by the sudden pressure relay.

Requirement R2

Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. In the case of multi-entity ownership, the entity that owns the BES interrupting device that operated is expected to use judgment to identify those Protection System operations that meet the definition of Misoperation under Requirement R1; however, if the entity that owns a BES interrupting device determines that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation, it must notify the other Protection System owner(s) that share Misoperation identification responsibility when the criteria in Requirement R2 is met.

This Requirement does not preclude the Protection System owners from initially communicating and working together to determine whether a Misoperation occurred and, if so, the cause. The BES interrupting device owner is only required to officially notify the other owners when it: (1) shares the Composite Protection System ownership with other entity(ies), (2) determines that a Misoperation occurred or cannot rule out a Misoperation, and (3) determines its Protection System component(s) did not cause a Misoperation or is unsure. Officially notifying the other owners without performing a preliminary review may unnecessarily burden the other owners with compliance obligations under Requirement R3, redirect valuable resources, and add little benefit to reliability. The BES interrupting device owner should officially notify other owners when appropriate within the established time period.

[8] "Misoperations Report." Reporting Multiple Occurrences. NERC Protection System Misoperations Task Force. http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. April 1, 2013. pg. 37 of 40.

The following is an example of a notification to another Protection System owner:

> **Example R2a:** Circuit breakers A and B at the Charlie station tripped from directional comparison blocking (DCB) relaying on 03/03/2014 at 15:43 UTC during an external Fault. As discussed last week, the fault records indicate that a problem with your equipment (failure to transmit) caused the operation.

> **Example R2b:** A generator unit tripped out immediately upon synchronizing to the grid due to a Misoperation of its overcurrent protection. The Transmission Owner owns the 230 kV generator breaker that operated. The Transmission Owner, as the owner of the BES interrupting device after determining that its Protection System components did not cause the Misoperation, notified the Generator Owner of the operation. The Generator Owner investigated and determined that its Protection System components caused the Misoperation. In this example, the Generator Owner's Protection System components did cause the Misoperation. As the owner of the Protection System components that caused the Misoperation, the Generator Owner is responsible for creating and implementing the CAP.

A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the notification criteria in Part 2.1.1 of Requirement R2. For example, if the same personnel within a registered entity perform the Misoperation identification for both the Generator Owner and Transmission Owner functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be covered in Requirement R1.

> **Example R2c:** Line A Composite Protection System (owned by entity 1) failed to operate for an internal Fault. As a result, the zone 3 portion of Line B's Composite Protection System (owned by entity 2) and zone 3 portion of Line C's Composite Protection System (owned by entity 3) operated to clear the Fault. Entity 2 and 3 notified entity 1 of the remote zone 3 operation.

For the case where a BES interrupting device operates to provide backup protection for a non-BES Element, the entity reviewing the operation is not required to notify the other owners of Protection Systems for non-BES Elements. No notification is required because this Reliability Standard is not applicable to Protection Systems for non-BES Elements.

Requirement R3

For Requirement R3 (i.e., notification received), the entity that also owns a portion of the Composite Protection System is expected to use judgment to identify whether the Protection System operation is a Misoperation. A combination of available information from resources such as counters, relay targets, SCADA, DME, and information from the other owner(s) would typically be used to determine whether or not a Misoperation occurred. The intent of the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. In many cases, it will not be necessary to leverage all available data to determine whether or not a Misoperation occurred. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. The entity may decide to identify the operation as a Misoperation to satisfy Requirement R1 and continue its investigation for a cause of the Misoperation under Requirement R4. If the continued investigative actions are inconclusive, the entity may declare no cause found and end its investigation.

The entity that is notified by the BES interrupting device owner is allotted the later of 60 calendar days from receipt of notification or 120 calendar days from the BES interrupting device operation date to determine if its portion of the Composite Protection System caused the Protection System operation. It is expected that in most cases of a jointly owned Protection System, the entity making notification would have been in communication with the other owner(s) early in the process. This means that the shorter 60 calendar days only comes into play if the notification occurs in the second half of the 120 calendar days allotted to the BES interrupting device owner in Requirement R1.

The Protection System review may be organized in a variety of ways such as in a report, database, spreadsheet, or list. The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. The BES interrupting device owner's notification received may be documented in a variety of ways such as an email or a facsimile.

Requirement R4

The entity in Requirement R4 (i.e., cause identification), whether it is the entity that owns the BES interrupting device or an entity that was notified, is expected to use due diligence in taking investigative action(s) to determine the cause(s) of an identified Misoperation for its portion of the Composite Protection System. The SMEs developing this standard recognize there will be cases where the cause(s) of a Misoperation will not be revealed during the allotted time periods in Requirements R1 or R3; therefore, Requirement R4 provides the entity a mechanism to continue its investigative work to determine the cause(s) of the Misoperation when the cause is not known.

A combination of available information from resources such as counters, relay targets, SCADA, DME, test results, and studies would typically be used to determine the cause of the Misoperation. At least one investigative action must be performed every two full calendar quarters until the investigation is completed.

The following is an example of investigative actions taken to determine the cause of an identified Misoperation:

> **Example R4a**: A Misoperation was identified on 03/18/2014. A line outage to test the Protection System was scheduled on 03/24/2014 for 12/15/2014 as the first investigative action (i.e., beyond the next two full calendar quarters) due to summer peak conditions. The protection engineer contacted the manufacturer on 04/10/2014 (i.e., within two full calendar quarters) to obtain any known issues. The engineer reviewed manufacturer's documents on 05/27/2014. The outage schedule was confirmed on 08/29/2014 and was taken on 12/15/2014. Testing was completed on 12/16/2014 (i.e., in the second two full quarters) revealing the microprocessor relay as the cause of the Misoperation. A CAP is being developed to replace the relay.

Periodic action minimizes compliance burdens and focuses the entity's effort on determining the cause(s) of the Misoperation while providing measurable evidence. The SMEs recognize that certain planned investigative actions may require months or years to schedule and complete; therefore, the entity is only required to perform at least one investigative action every two full calendar quarters. If an investigative action is performed in the first quarter of a calendar year, the next investigative action would need to be performed by the end of the third calendar quarter. If an investigative action is performed in the last quarter of a calendar year, the next investigative action would need to be performed by the end of the second calendar quarter of the following calendar year. Investigative actions may include a variety of actions, such as reviewing DME records, performing or reviewing studies, completing relay calibration or testing, requesting manufacturer review, requesting an outage, or confirming a schedule.

The entity's investigation is complete when it identifies the cause of the Misoperation or makes a declaration that no cause was determined. The declaration is intended to be used if the entity determines that investigative actions have been exhausted or have not provided direction for identifying the Misoperation cause. Historically, approximately 12% of Misoperations are unknown or unexplainable.[9]

Although the entity only has to document its specific investigative actions taken to determine the cause(s) of an identified Misoperation, the entity should consider the benefits of formally organizing (e.g., in a report or database) its actions and findings. Well documented investigative actions and findings may be helpful in future investigations of a similar event or circumstances. A thorough report or database may contain a detailed description of the event, information gathered, investigative actions, findings, possible causes, identified causes, and conclusions. Multiple owners of a Composite Protection System might consider working together to produce a common report for their mutual benefit.

[9] NERC System Protection and Control Subcommittee. Misoperations Report. April 1, 2013: http://www.nerc.com/docs/pc/psmtf/PSMTF_Report.pdf. Figure 15: NERC Wide Misoperations by Cause Code. pg. 22 of 40.

The following are examples of a declaration where no cause was determined:

Example R4b: A Misoperation was identified on 04/11/2014. All relays at station A and B functioned properly during testing on 08/26/2014 as the first investigative action. The carrier system functioned properly during testing on 08/27/2014. The carrier coupling equipment functioned properly during testing on 08/28/2014. A settings review completed on 09/03/2014 indicated the relay settings were proper. Since the equipment involved in the operation functioned properly during testing, the settings were reviewed and found to be correct, and the equipment at station A and station B is already monitored. The investigation is being closed because no cause was found.

Example R4c: A Misoperation was identified on 03/22/2014. The protection scheme was replaced before the cause was identified. The power line carrier or PLC based protection was replaced with fiber-optic based protection with an in-service date of 04/16/2014. The new system will be monitored for recurrence of the Misoperation.

Requirement R5

Resolving the causes of Protection System Misoperations benefits BES reliability by preventing recurrence. The Corrective Action Plan (CAP) is an established tool for resolving operational problems. The NERC Glossary defines a Corrective Action Plan as, *"A list of actions and an associated timetable for implementation to remedy a specific problem."* Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the Misoperation cause is identified in Requirement R1, R3 or R4, Requirement R5 requires Protection System owner(s) to develop a CAP, or explain why corrective actions are beyond the entity's control or would not improve BES reliability. The entity must develop the CAP or make a declaration why additional actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken within 60 calendar days of first determining a cause.

The SMEs developing this standard recognize there may be multiple causes for a Misoperation. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a single or multiple CAP(s) to correct multiple causes of a Misoperation. The 60 calendar day period for developing a CAP (or declaration) is established on the basis of industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent Misoperation recurrence, the timetable for executing such actions, and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. The evaluation of these other Protection Systems aims to reduce the risk and likelihood of similar Misoperations in other Protection Systems. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations. The evaluation may result in the owner including actions to address Protection Systems at other locations or the reasoning for not taking any action. The CAP and an evaluation of other Protection Systems including other locations must be developed to complete Requirement R5.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined capacitor replacement was not necessary.

For completion of each CAP in Examples R5a through R5d, please see Examples R6a through R6d.

> **Example R5a:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay has not been experiencing problems and is systematically being replaced with microprocessor relays as Protection Systems are modernized. Therefore, it was assessed that a program for wholesale preemptive replacement of capacitors in this type of impedance relay does not need to be established for the system.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5b:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, a program should be established by 12/01/2014 for wholesale preemptive replacement of capacitors in this type of impedance relay.

The following is an example of a CAP for a relay Misoperation that was applying a standing trip due to a failed capacitor within the relay and the evaluation of the cause at similar locations which determined the capacitors need preemptive correction action.

> **Example R5c:** Actions: Remove the relay from service. Replace capacitor in the relay. Test the relay. Return to service or replace by 07/01/2014.
>
> Applicability to other Protection Systems: This type of impedance relay is suspected to have previously tripped at other locations because of the same type of capacitor issue. Based on the evaluation, the preemptive replacement of capacitors in this type of impedance relay should be pursued for the identified stations A through I by 04/30/2015.
>
> A plan is being developed to replace the impedance relay capacitors at stations A, B, and C by 09/01/2014. A second plan is being developed to replace the impedance relay capacitors at stations D, E, and F by 11/01/2014. The last plan will replace the impedance relay capacitors at stations G, H, and I by 02/01/2015.

The following is an example of a CAP for a relay Misoperation that was due to a version 2 firmware problem and the evaluation of the cause at similar locations which determined the firmware needs preemptive correction action.

> **Example R5d:** Actions: Provide the manufacturer fault records. Install new firmware pending manufacturer results by 10/01/2014.
>
> Applicability to other Protection Systems: Based on the evaluation of other locations and a risk assessment, the newer firmware version 3 should be installed at all installations that are identified to be version 2. Twelve relays were identified across the system. Proposed completion date is 12/31/2014.

The following are examples of a declaration made where corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken.

> **Example R5e:** The cause of the Misoperation was due to a non-registered entity communications provider problem.
>
> **Example R5f:** The cause of the Misoperation was due to a transmission transformer tapped industrial customer who initiated a direct transfer trip to a registered entity's transmission breaker.

In situations where a Misoperation cause emanates from a non-registered outside entity, there may be limited influence an entity can exert on an outside entity and is considered outside of an entity's control.

The following are examples of declarations made why corrective actions would not improve BES reliability.

> **Example R5g:** The investigation showed that the Misoperation occurred due to transients associated with energizing transformer ABC at Station Y. Studies show that de-sensitizing the relay to the recorded transients may cause the relay to fail to operate as intended during power system oscillations.
>
> **Example R5h:** As a result of an operation that left a portion of the power system in an electrical island condition, circuit XYZ within that island tripped, resulting in loss of load within the island. Subsequent investigation showed an overfrequency condition persisted after the formation of that island and the XYZ line protective relay operated. Since this relay was operating outside of its designed frequency range and would not be subject to this condition when line XYZ is operated normally connected to the BES, no corrective action will be taken because BES reliability would not be improved.

Example R5i: During a major ice storm, four of six circuits were lost at Station A. Subsequent to the loss of these circuits, a skywire (i.e., shield wire) broke near station A on line AB (between Station A and B) resulting in a phase-phase Fault. The protection scheme utilized for both protection groups is a permissive overreaching transfer trip (POTT). The Line AB protection at Station B tripped timed for this event (i.e., Slow Trip – During Fault) even though this line had been identified as requiring high speed clearing. A weak infeed condition was created at Station A due to the loss of 4 transmission circuits resulting in the absence of a permissive signal on Line AB from Station A during this Fault. No corrective action will be taken for this Misoperation as even under N-1 conditions, there is normally enough infeed at Station A to send a proper permissive signal to station B. Any changes to the protection scheme to account for this would not improve BES reliability.

A declaration why corrective actions are beyond the entity's control or would not improve BES reliability should include the Misoperation cause and the justification for taking no corrective action. Furthermore, a declaration that no further corrective actions will be taken is expected to be used sparingly.

Requirement R6

To achieve the stated purpose of this standard, which is to identify and correct the causes of Misoperations of Protection Systems for BES Elements, the responsible entity is required to implement a CAP that addresses the specific problem (i.e., cause(s) of the Misoperation) through completion. Protection System owners are required in the implementation of a CAP to update it when actions or timetable change, until completed. Accomplishing this objective is intended to reduce the occurrence of future Misoperations of a similar nature, thereby improving reliability and minimizing risk to the BES.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip (See also, Example R5a).

Example R6a: Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.

CAP completed on 06/25/2014.

The following is an example of a completed CAP for a relay Misoperation that was applying a standing trip that resulted in the correction and the establishment of a program for further replacements (See also, Example R5b).

> **Example R6b:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> A program for wholesale preemptive replacement of capacitors in this type of impedance relay was established on 10/28/2014.
>
> CAP completed on 10/28/2014.

The following is an example of a completed CAP of corrective actions with a timetable that required updating for a failed relay and preemptive actions for similar installations (See also, Example R5c).

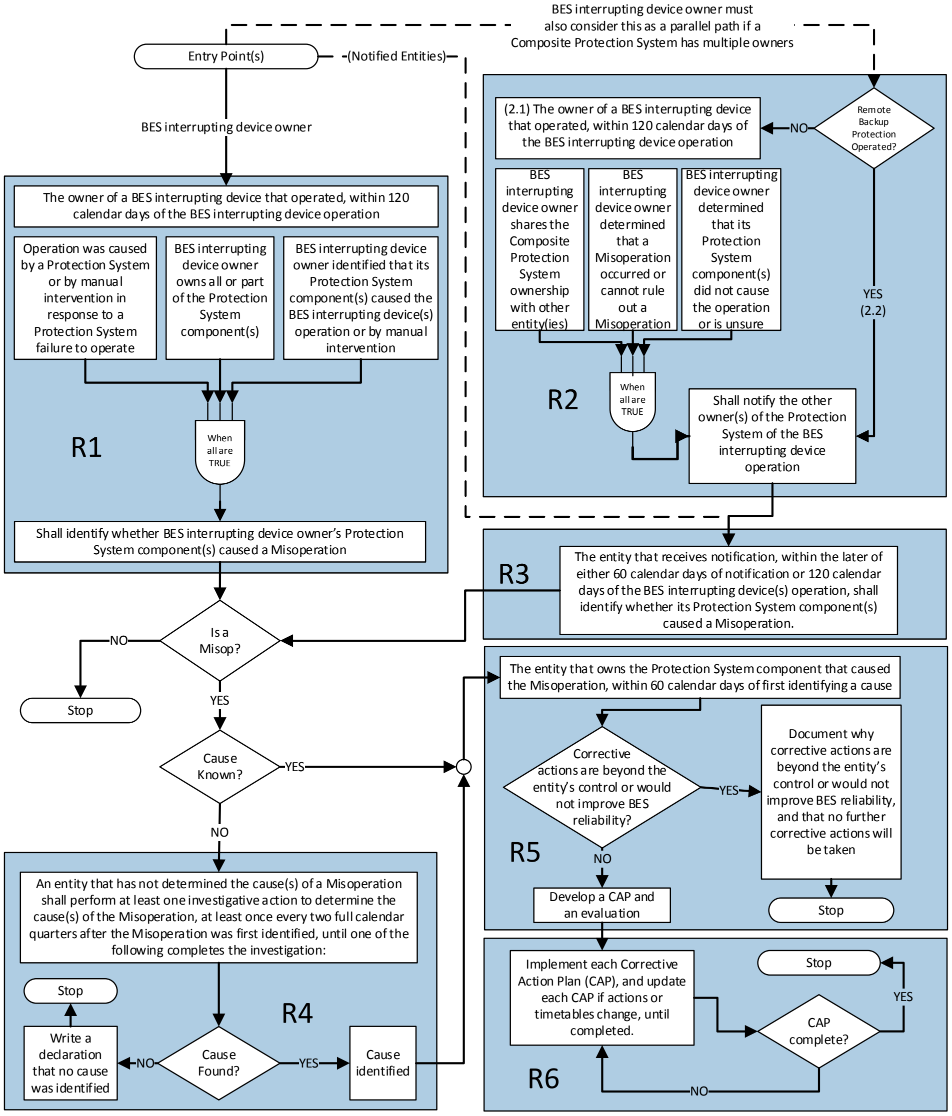
> **Example R6c:** Actions: The impedance relay was removed from service on 06/02/2014 because it was applying a standing trip. A failed capacitor was found within the impedance relay and replaced. The impedance relay functioned properly during testing after the capacitor was replaced. The impedance relay was returned to service on 06/05/2014.
>
> The impedance relay capacitor replacement was completed at stations A, B, and C on 08/16/2014. The impedance relay capacitor replacement was completed at stations D, E, and F on 10/24/2014. The impedance relay capacitor replacement for stations G, H, and I were postponed due to resource rescheduling from a scheduled 02/01/15 completion to 04/01/2015 completion. Capacitor replacement was completed on 03/09/2015 at stations G, H, and I. All stations identified in the evaluation have been completed.
>
> CAP completed on 03/09/2015.

The following is an example of a completed CAP for corrective actions with updated actions for a firmware problem and preemptive actions for similar installations. (See also, Example R5d).

> **Example R6d:** Actions: fault records were provided to the manufacturer on 06/04/2014. The manufacturer responded that the Misoperation was caused by a bug in version 2 firmware, and recommended installing version 3 firmware. Version 3 firmware was installed on 08/12/2014.
>
> Nine of the twelve relays were updated to version 3 firmware on 09/23/2014. The manufacturer provided a subsequent update which was determined to be beneficial for the remaining relays. The remaining three of twelve relays identified as having the version 2 firmware were updated to version 3.01 firmware on 11/10/2014.
>
> CAP completed on 11/10/2014.

The CAP is complete when all of the actions identified within the CAP have been completed.

Process Flow Chart: Below is a graphical representation demonstrating the relationships between Requirements:



Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction
- Definitions of "Composite Protection System" and "Misoperation"

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided by a different Element's Protection System(s) is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition for which it is designed, such as a power swing, undervoltage,

overexcitation, or loss of excitation. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements, with the following exclusions:
  - Non-protective functions that are embedded within a Protection System.
  - Protective functions intended to operate as a control function during switching.
  - Special Protection Systems (SPS).
  - Remedial Action Schemes (RAS).
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

The standard, the revised definition of "Misoperation," and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of "Misoperation," and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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

The existing standards, PRC-003-1 and PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-3.

Implementation Plan

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Requested Approvals

- PRC-004-3 – Protection System Misoperation Identification and Correction
- Definitions of "Composite Protection System" and "Misoperation"

Requested Retirements

- PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection System
- PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Prerequisite Approvals

- None

Revisions to Defined Terms in the NERC Glossary

The standard drafting team proposes the following new definition:

Composite Protection System:

The total complement of Protection System(s) that function collectively to protect an Element. Backup protection provided ~~to~~by a ~~remote~~different Element's Protection System(s) is excluded.

The standard drafting team proposes the following revised definition:

Misoperation:

The failure of a Composite Protection System to operate as intended for protection purposes. Any of the following is a Misoperation:

1. **Failure to Trip – During Fault** – A failure of a Composite Protection System to operate for a Fault condition for which it is designed. The failure of a Protection System component is not a Misoperation as long as the performance of the Composite Protection System is correct.
2. **Failure to Trip – Other Than Fault** – A failure of a Composite Protection System to operate for a non-Fault condition ~~if~~for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. The failure of a Protection System component is not a

Misoperation as long as the ~~duration of its operating time resulted in~~performance of the ~~operation of at least one other Element's~~ Composite Protection System is correct.

3. **Slow Trip – During Fault** – A Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
4. **Slow Trip – Other Than Fault** – A Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, undervoltage, overexcitation, or loss of excitation if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System.
5. **Unnecessary Trip – During Fault** – An unnecessary Composite Protection System operation for a Fault condition on another Element.
6. **Unnecessary Trip – Other Than Fault** – An unnecessary Composite Protection System operation for a non-Fault condition. A Composite Protection System operation that is caused by personnel during on-site maintenance, testing, inspection, construction or commissioning activities is not a Misoperation.

General Considerations

The implementation period allows adequate time for applicable entities to develop or modify its procedures and processes for reviewing Protection System operations. The development and implementation of a Corrective Action Plan remains within the scope of PRC-004; therefore, little additional time and resources should be needed to account for the increased detail in the required performance identified in the proposed PRC-004-3 Reliability Standard. The obligation for reporting Misoperations has been removed from PRC-004 and is being developed under the NERC Rules of Procedure, Section 1600 – Request for Data or Information.

Applicability

This standard applies to the following functional entities:

- Transmission Owner
- Generator Owner
- Distribution Provider

This standard applies to the following Facilities:

- Protection Systems for BES Elements~~. Non-protective functions that are embedded within a Protection System are excluded. Protective functions intended to operate as a control function during switching are excluded.~~, with the following exclusions:
  - o Non-protective functions that are embedded within a Protection System.
  - o Protective functions intended to operate as a control function during switching.
  - o Special Protection Systems (SPS).
  - o Remedial Action Schemes (RAS).
- Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.

Effective Dates of New or Revised Standards and Definitions

The standard, the revised definition of "Misoperation~~"~~,~~"~~" and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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, the revised definition of "Misoperation~~"~~,~~"~~" and the new definition of "Composite Protection System" shall become effective on the first day of the first calendar quarter that is twelve (12) months 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

The existing standards, PRC-003-1 and PRC-004-2.1a, shall be retired at midnight of the day immediately prior to the Effective Date of PRC-004-3.

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the standard drafting team is recommending revisions to the standard, those changes are identified in the "Translation to PRC-004-3 or Other Action" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered entity functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based standard (RBS) construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also directs focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners that share a Misoperation identification responsibility of the Composite Protection System when it determines (or is unsure) its Protection System component(s) did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		continue its investigative work to determine the cause(s) of an identified Misoperation, if not determined in R1 or R3, until the cause(s) is determined or the entity declares that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**4.2.** Facilities: **4.2.1** Protection Systems for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded and will be addressed in phase two of this project and have been excluded in the Applicability.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	Protection System component(s) caused a Misoperation: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to a Protection System failure to operate.	ensuring that other owners had a responsibility to be involved in the review and analysis.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated	Requirement R2 asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and	the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation is identified (or cannot be ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	be provided to the other Protection System owner(s) for which that backup protection was provided.	identify a possible Misoperation under Requirement R3 by the other owner(s).
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	cause(s) of a Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of the applicable entities. As such, reporting to Regional Entities will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability; identify

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		remediation techniques; and publicize lessons learned for the industry. Metrics will be validated and shared with each Regional Entity. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	document in a declaration that a CAP is not practical. The entity must explain in a declaration why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection Systems for BES Elements without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard, revised definition of "Misoperation," and new definition of "Composite Protection System" provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the Regional Entity's (formerly Regional Reliability

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Organization or RRO) approval of procedures. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the affected Transmission	None.	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) to the applicable entities. Requiring the applicable entities to distribute procedures is an activity or task that does

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.		little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS).	The same applicable entities will transition to the new PRC-004-3 standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	Remedial Action Schemes (RAS) are addressed in phase two of this project and have been excluded in the Applicability.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and	The currently approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3).

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	**1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to a Protection System failure to operate. **R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the	The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation is identified (or cannot be ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 by the other owner. Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	R4. Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar	in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review. Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause(s) of an identified Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those Protection Systems at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity must document in a declaration that a CAP actions are beyond the entity's control or would not improve BES reliability. The entity must explain in a declaration why no further action will be taken.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	None.	Since the NERC Rules of Procedure, Section 1600 Request for Data or Information will replace the reporting obligations, NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Mapping Document

Project 2010-05.1 Protection Systems: Phase 1 (Misoperations)

Revisions or Retirements to Already Approved Standards

This mapping document shows the translation of PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations into the proposed PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard. The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the standard drafting team is recommending revisions to the standard, those changes are identified in the "Translation to PRC-004-3 or Other Action" column.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Regional Reliability Organization	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed standard properly assigns responsibility to the registered entity functions that are responsible for Protection System Misoperation identification and correction. The Transmission Owner, Generator Owner, and Distribution Provider, by function, are Protection System asset owners and are in the best position be aware of and apply resources to review Protection System operations.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
R1. Each Regional Reliability Organization shall establish, document and maintain its procedures for, review, analysis, reporting and mitigation of transmission and generation Protection System Misoperations. These procedures shall include the following elements:		The Requirements in the proposed PRC-004-3 standard by their results-based standard (RBS) construction requires performance that is implicit of having procedures for the analysis of Protection System operations (R1, R2, R3, and R4) and mitigation of identified Misoperations (R5 and R6). The proposed requirements also directs focus to areas most important to reliability. For example, Requirement R1 requires the applicable entity to initiate a review upon a Bulk Electric System (BES) interrupting device operation and identify any Misoperation. Requirement R2 requires the applicable entity to notify all other owners that share a Misoperation identification responsibility of the Composite Protection System when it determines (or is unsure) its Protection System component(s) did not cause the BES interrupting device operation or it cannot rule out a Misoperation. Requirement R3 requires the notified entity to identify any Misoperation of its Protection System component(s) similar to Requirement R1. Requirement R4 directs the applicable entity to

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		continue its investigative work to determine the cause(s) of an identified Misoperation, if not determined in R1 or R3, until the cause(s) is determined or the entity declares that it is unable to determine the cause. Requirements R5 and R6 for developing and implementing a Corrective Action Plan (CAP) are also implicit of having a documented procedure. The implicit performance required by Requirements R1 through R6 necessitate that an entity have procedures to accomplish the objectives of the proposed standard. Requiring the applicable entities to have procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R1.1. The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**4.2.** Facilities: **4.2.1** Protection Systems for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded	The previous PRC-003-1, Requirement R1.1 required the Regional Reliability Organization (RRO) to identify the Protection Systems to be reviewed and analyzed for Misoperation. The applicable Facilities have been clarified in the proposed PRC-004-3 to include Protection Systems for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS). **4.2.2** Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and Remedial Action Schemes (RAS) are excluded and will be addressed in phase two of this project and have been excluded in the Applicability.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused	The applicable entities will be required to identify whether a Misoperation occurred for each BES interrupting device operation which meet criteria 1.1 through 1.3. Requirement R1 is most clearly the direct carryover from the PRC-003-1 Reliability Standard which involves the "owner" of the Protection System. The previous standard was silent on the responsibilities of other Protection System owners and had no provision for

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	a Misoperation ~~under the following circumstances~~: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and **1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and **1.3** The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation~~.~~ or was caused by manual intervention in response to a Protection System failure to operate.	ensuring that other owners had a responsibility to be involved in the review and analysis.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated	Requirement R2 asserts a responsibility on the initiating entity (i.e., BES interrupting device owner) to notify other owners of the Composite Protection System when

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and	the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation ~~occurred~~is identified (or cannot be ruled out) in accordance with Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	2.1.2 The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall	(Part 2.2) Since Requirement R1 initiates the reliability activity upon the operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device ~~owner in performing Requirement R1 determines that it's Protection System operated~~operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device ~~which~~ has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified,

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	be provided to the other Protection System owner(s) for which that backup protection was provided.	thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 ~~for~~by the other owner~~.~~(s).
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed for Misoperations (due to their potential impact on BES reliability).	**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.	Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for Misoperations similar to Requirement R1. It is common practice for the BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review.
(Continued) **R1.1.** The Protection Systems to be reviewed and analyzed	**R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a	Requirement R4 is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
for Misoperations (due to their potential impact on BES reliability).	Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified.	cause(s) of a Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative action every two full calendar quarters until the entity determines the cause(s) or declares that it could not determine the cause.
R1.2. Data reporting requirements (periodicity and format) for Misoperations.	None.	NERC Rules of Procedure, Section 1600 Request for Information or Data will replace the reporting obligations of the applicable entities. As such, reporting to Regional ~~reporting~~Entities will end and continent-wide single reporting to the Electric Reliability Organization (ERO) will be required. The ERO will analyze the data to: develop meaningful metrics; identify trends in Protection System performance that negatively impact reliability;

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		identify remediation techniques; and publicize lessons learned for the industry. Metrics will be validated and shared with each ~~Region~~Regional Entity. The removal of the data collection from the standard does not result in a reduction of reliability.
R1.3. Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the	The proposed PRC-004-3, Requirement R5 provides a step not apparent in the previous PRC-003-1 which is the development of a Corrective Action Plan (CAP) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity may

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	entity's control or would not improve BES reliability, and that no further corrective actions will be taken.	document ~~this as well and not make a change. In cases where the entity, in its judgment, determines~~ in a declaration that a CAP is not practical ~~for improving BES reliability, the~~. The entity must explain in a declaration ~~its conclusions~~ why no further action will be taken.
(Continued) **R1.3.** Process for review, analysis follow up, and documentation of Corrective Action Plans for Misoperations.	**R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed.	Requirement R6 requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R1.4. Identification of the Regional Reliability Organization group responsible for the procedures and the process for approval of the procedures.	None.	The proposed PRC-004-3 now requires the applicable entities (GO, DP, and TO) to individually address Misoperations of its Protection Systems for BES Elements without regard to the Region or Regions in which it owns Protection Systems for BES Elements. The proposed PRC-004-3 Reliability Standard, revised definition of "Misoperation," and new definition of "Composite Protection System" provide sufficient clarity to entities; therefore, there is no reliability benefit to obtain the

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
		Regional Entity's (formerly Regional Reliability Organization or RRO) approval~~.~~ of procedures. Each applicable entity will be measured on its performance with the proposed PRC-004-3 requirements.
R2. Each Regional Reliability Organization shall maintain and periodically update documentation of its procedures for review, analysis, reporting, and mitigation of transmission and generation Protection System Misoperations.	**4. Applicability:** **4.1. Functional Entities:** **4.1.1** Transmission Owner **4.1.2** Generator Owner **4.1.3** Distribution Provider	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no need to have a specific requirement for dictating the updating of such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) or applicable entities. Requiring the applicable entities to update procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.
R3. Each Regional Reliability Organization shall distribute procedures in Requirement 1 and any changes to those procedures, to the	None.	The proposed PRC-004-3 implicitly requires each applicable entity to have its own procedures and processes; therefore, there is no longer a need to distribute such procedures or processes by the previous Regional Reliability Organization (now Regional Entity) ~~or~~to the applicable entities. Requiring the applicable

Standard: PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
affected Transmission Owners, Distribution Providers that own transmission Protection Systems, and Generator Owners within 30 calendar days of approval of those procedures.		entities to distribute procedures is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
4. Applicability: **4.1.** Transmission Owner **4.2.** Distribution Provider that owns a transmission Protection System **4.3.** Generator Owner	**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 for BES Elements, with the following exclusions: **4.2.1.1** Non-protective functions that are embedded within a Protection System. **4.2.1.2** Protective functions intended to operate as a control function during switching. **4.2.1.3** Special Protection Systems (SPS). **4.2.1.4** Remedial Action Schemes (RAS).	The same applicable entities will transition to the new PRC-004-3 standard. The clause about the Distribution Provider "*that owns a transmission Protection System*" has been removed because it was ambiguous. This clause is replaced by "*Protection Systems for BES Elements*" found in Section 4.2, Facilities and applies to all the applicable entities. Having the Applicability section address Facilities specifically removes the ambiguity of what a "*transmission Protection System*" includes. The proposed PRC-004-3 standard is specific that it includes those Protection Systems for BES Elements, including UFLS that is intended to trip one or more BES Elements. Additional language is provided for clarity that non-protective functions and those protective functions that are intended to operate as a control function (e.g., a reverse power relay operated to remove a generating unit from service) are not applicable. The standard's Applicability is further clarified to include underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements to be more precise. Protection Systems associated with Special Protection Systems (SPS) and

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	4.2.2 Underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements.	Remedial Action Schemes (RAS) are addressed in phase two of this project and have been excluded in the Applicability.
R1. The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures. **R2.** The Generator Owner shall analyze its generator and generator	**R1.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated under the circumstances in 1.1 through 1.3 shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation~~ under the following circumstances~~: **1.1** The BES interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and	The currently approved standard PRC-004-2.1a, Requirements R1 and R2 include three levels of performance which is analyze (Protection System operations), develop (CAP), and implement (CAP). The proposed standard, which includes the same three applicable entities (DP, GO, and TO), divides the three levels of performance into six discrete Requirements. Requirement R1 provides the "analyze" portion, requiring the initiating BES interrupting device owner to review its Protection System for each BES interrupting device operation that meets the three criteria (i.e., 1.1 thorough 1.3).

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations

Requirement in Approved Standard	Translation to PRC-004-3 or Other Action	Comments
interconnection Facility Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.	**1.2** The BES interrupting device owner owns all or part of the Composite Protection System; and 1.3 The BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation or was caused by manual intervention in response to a Protection System failure to operate. **R2.** Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, provide notification as described in 2.1 and 2.2. **2.1** When a BES interrupting device operation by a Composite Protection System or by manual intervention in response to a	The "analyze" portion is further clarified in the proposed Requirement R2 by ensuring that any other owners of the Composite Protection System are notified when the cause of a Protection System operation was not caused (or is undetermined) by the BES interrupting device owner and when a Misoperation ~~occurred~~is identified (or cannot be ruled out) in accordance with ~~criteria~~Part 2.1, including sub-parts 2.1.1 through 2.1.3.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	Protection System failure to operate, notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System under the following circumstances: **2.1.1** The BES interrupting device owner shares the Composite Protection System ownership with any other entity; and **2.1.2** The BES interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and **2.1.3** The BES interrupting device owner has determined that its Protection System component(s) did not cause	

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	the BES interrupting device(s) operation or cannot determine whether its Protection System components caused the BES interrupting device(s) operation. **2.2** For a BES interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's BES Element, notification of the operation shall be provided to the other Protection System owner(s) for which that backup protection was provided. **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2 shall, within the later of 60 calendar days of notification or 120 calendar days of the BES	(Part 2.2) Since Requirement ~~R3 provides~~R1 initiates the ~~necessary performance for~~ reliability activity upon the ~~notified~~operation of a BES interrupting device, Requirement R1 does not address the case of a Protection System ~~owner~~ failure where a remote BES interrupting device operates. The second Part 2.2 of Requirement R2 is a provision to require notification to the other owners when a remote BES interrupting device operates as backup protection for a condition on another entity's BES Element. This generally indicates that another BES interrupting device has most likely failed to operate. Part 2.2 requires the other owner for which backup protection was provided to be notified, thus initiating the reliability activity to identify a possible Misoperation under Requirement R3 by the other owner. Requirement R3 places responsibility on the applicable entity that receives notification to review its Protection System component(s) for ~~Misoperation~~Misoperations similar to Requirement R1. It is common practice for the

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation. **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement R1 or R3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, until one of the following completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System	BES interrupting device owner that initiates the review to be in communication and collaboration with other Protection System component(s) owners during its review within the 120 calendar day period. The shorter 60 calendar day period for the notified entity assures that in the rare case where the notifying entity takes the majority of its allotted time (120 calendar days) to review an operation, the receiving entity will always have a minimum and reasonable time (60 calendar days) to conduct its review. ~~Last,~~ Requirement R4 ~~requires~~ is essentially a new requirement to determine the cause(s) of a Misoperation where the previous requirements (i.e., R1 or R3) failed to reveal the cause(s) of an identified Misoperation. In most cases, the cause(s) of a Misoperation will be revealed during the course of review and when the cause(s) is not readily apparent, the applicable entity is required in Requirement R4 to conduct at least one investigative ~~actions~~ action every two full calendar quarters until ~~it~~the entity determines the cause(s) or declares that it ~~has been unable to~~could not determine the cause~~(s)~~.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	component(s) that caused the Misoperation shall, within 60 calendar days of first identifying a cause of the Misoperation: • Develop a Corrective Action Plan (CAP) for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations, or • Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken. **R6.** Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP developed in Requirement R5, and update each CAP	The proposed PRC-004-3, Requirement R5 ~~addresses~~provides a step not apparent in the ~~"develop" a~~ previous PRC-003-1 which is the development of a Corrective Action Plan (CAP~~)" portion,~~) within 60 calendar days of first identifying the Misoperation cause. Requirement R5 also requires each applicable entity to perform an evaluation of the CAP's applicability to the entity's other Protection Systems, including those Protection Systems at other locations. Furthermore, Requirement R5 accounts for those cases why corrective actions are beyond the entity's control or would not improve BES reliability and that no further corrective actions will be taken. This could be a result of a cause created by a non-registered third party, such as a communication provider. Also, should implementing the changes not improve BES reliability, the entity must document in a declaration that a CAP actions are beyond the entity's control or would not improve BES reliability. The entity must explain in a declaration why no further action will be taken.

Standard: PRC-004-2.1a - Analysis and Mitigation of Transmission and Generation Protection System Misoperations		
Requirement in Approved Standard	**Translation to PRC-004-3 or Other Action**	**Comments**
	if actions or timetables change, until completed.	Requirement R6 ~~addresses the "implement" portion of the CAP~~requires the implementation of the CAP. The applicable entity must update the CAP if actions or timetables change until the CAP is completed.
R3. The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.	None.	Since the NERC Rules of Procedure, Section 1600 Request for Data or Information will replace the reporting obligations, NERC will receive the data on a periodic basis, analyze, establish metrics, and share results accordingly with the Regional Entities as well as industry. Having reporting obligations as a Requirement is an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

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-004-3 – Protection System Misoperation Identification and Correction.

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 Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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 VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,145 (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at fn 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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 Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of "High." The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". The performance activity that has been isolated in Requirement R1 of PRC-004-3, to "review" (similar to "analyze"), is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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. Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R2	
	Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan”. This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 (“…shall provide Facility Ratings (for its solely and jointly owned Facilities…”), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 (“…shall provide appropriate equipment characteristics and system data…”), IRO-015-1 – Special Protection System Data and Documentation, R1.1 (“…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas.”), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 (“…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.”) which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 (“…shall provide documentation…”), PRC-016-0.1 – Special Protection System Misoperations, R3 (“…that owns an SPS shall provide documentation of the misoperation analyses…”), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 (“…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2			
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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. Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR

VRF and VSL Justifications – PRC-004-3, R2			
			The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.		
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b:		

VRF and VSL Justifications – PRC-004-3, R2	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which both have a VRF of High. This Requirement R3, to "review" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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. Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage.

VRF and VSL Justifications – PRC-004-3, R3			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R4	
	An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO), which have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." This Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium.

VRF and VSL Justifications – PRC-004-3, R4	
	A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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. Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R4			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard.		

VRF and VSL Justifications – PRC-004-3, R4	
	This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VSL G4 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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.

VRF and VSL Justifications – PRC-004-3, R5			
	An unresolved cause of a Misoperation could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO),which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan". This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future misoperations.") and PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…") which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6			
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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. An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.

VRF and VSL Justification – PRC-004-3, R6	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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 Justification – PRC-004-3, R6	
Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level 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 this Requirement.
FERC VSL G4 Violation Severity Level 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.

Violation Risk Factors and Violation Severity Level Justifications

PRC-004-3 – Protection System Misoperation Identification and Correction

Project 2010-05.1 – Protection System (Misoperations)

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-004-3 ~~—~~– Protection System ~~Misoperations~~Misoperation Identification and Correction.

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~~base penalty amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Protection System Misoperations Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project.

NERC Criteria - Violation Risk Factors

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 Violation Risk Factor Guidelines

The standard drafting team (SDT) also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors 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~~VRF Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System: [2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination

[1] ~~North American Electric~~*N. Am. Elec.* *Reliability Corp.*, 119 FERC ¶ 61,145~~,~~ (2007) ("VRF Order"), *order on reh'g and compliance filing*, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] *Id.* at ~~footnote~~fn 15.

- 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 Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors 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 Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor 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.

VRF Discussion

The ~~following~~ discussion below in the tables addresses how the SDT considered FERC's VRF Guidelines 1 through 5. PRC-004-3 – Protection System Misoperation Identification and

Correction is a revision of PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations~~." The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations. In FERC Order No. 693, the Commission identified PRC-003-0 as a "fill-in-the-blank" standard. The Order stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-0. Because PRC-003-0 (now PRC-003-1) is not enforceable, there is not a mandatory requirement for Regional Entity procedures to support the requirements of PRC-004-2.1a. This is a potential reliability gap; consequently, PRC-004-3~~ and combines the reliability intent of the two legacy standards PRC-003-1 and PRC-004-2.1a.

The proposed PRC-004-3 Reliability Standard has six (6) discrete requirements that incorporate and enhance the intent of the requirements of PRC-004-2.1a and PRC-003-1.[3] First, the revised standard requires the Transmission Owner, Generator Owner, and Distribution Provider to review each BES interrupting device operation meeting the criteria in Requirement R1, which includes: when caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate and identify each that is a Misoperation; regardless of whether the BES interrupting device owner owns all or part of the Composite Protection System; and when BES interrupting device owner identified that its Protection System component(s) caused the BES interrupting device(s) operation.

Second, the BES interrupting device owner is required to notify the other Composite Protection System component owner(s) when the criteria in Requirement R2 are met, which includes: Composite Protection System ownership is shared with another owner; the BES interrupting device owner determined that a Misoperation occurred or cannot rule out a Misoperation; and the BES interrupting device owner determined that its Protection System component(s) did not cause the BES interrupting device(s) operation or is unsure.

Third, if a Transmission Owner, Generator Owner, or Distribution Provider is notified by a BES interrupting device owner that the Composite Protection System operated, it must review the operation according to Requirement R3. In most cases, Requirement R1 or R3 will reveal the cause of the Misoperation. If not, Requirement R4 mandates the entity perform investigative action(s) to determine the cause(s) as the fourth discrete Requirement. If a cause is not identified, the entity either may continue its investigation until a cause is identified or the entity may write a declaration that no cause was identified. If a cause is identified, the entity advances to the fifth Requirement.

In Requirement R5, the entity whose Protection System component was identified as the cause of the Misoperation must either develop a Corrective Action Plan (CAP) or explain in a declaration why it cannot correct the cause of the Misoperation. In developing a Corrective Action Plan (CAP) for the identified Protection System component(s), the entity must perform

[3] The Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems requires Regional Entities to establish procedures for analysis of Misoperations.

an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations. If the entity determines that corrective actions are beyond the entity's control or would not improve BES reliability, it must explain this in a declaration why no further corrective actions will be taken.

In the last Requirement R6, the entity must implement and complete the CAP. The entity must update the CAP during implementation when actions or timetables change.

The requirements of the proposed PRC-004-3 do not map, one-to-one, with the Requirements of the two legacy standards, PRC-003-1 and PRC-004-2.1a. The new Requirements comingle various reliability attributes of the legacy standards with precise reliability objectives~~, thus a Requirement-to-Requirement comparison of VRFs is not possible.~~. In developing the new VRFs for the Requirements of PRC-004-3, the Standard Drafting Team carefully considered the NERC criteria for developing VRFs, as well as the FERC VRF guidelines. The VRFs of the FERC approved PRC-004-2.1a – Analysis and Mitigation of Transmission and Generation Protection System Misoperations (R1 & R2 – High VRF), PRC-004-WECC-1 – Protection System and Remedial Action Scheme Misoperation (R1 – Lower VRF), PRC-016-0.1 – Special Protection System Misoperation (R2 – Medium VRF), and PRC-022-1 – Under-Voltage Load Shedding Program Performance (R1 & R1.5 – Medium VRF), all influenced (citing FERC VRF Guideline 3) the drafting team's VRF decisions, as such, the VRFs for PRC-004-3 Requirements R1 through R6 are assigned a VRF of Medium.

NERC Criteria - Violation Severity Levels

Violation Severity Levels (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.

Violation severity levels 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	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	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	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 full intent of the requirement.	intent of the requirement.	value in meeting the intent of the requirement.	the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order on Violation Severity Levels

In its June 19, 2008 Order on Violation Severity Levels, FERC indicated it would use the following four guidelines for determining whether to approve VSLs:

Guideline 1: Violation Severity Level 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: Violation Severity Level 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: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level 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 – PRC-004-3, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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.~~ Composite Protection System operations reviewed for proper operation by an owner is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is ~~unlikely~~not in itself likely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard:

VRF and VSL Justifications – PRC-004-3, R1	
	This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO~~).~~), which both have a VRF of “High.” The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan~~” which both have a VRF of High. This~~”. The performance activity that has been isolated in Requirement R1 of PRC-004-3, to “review” (similar to “analyze”), ~~comports~~is consistent with similar requirements in Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement ~~contained multiple activities and is ambiguous. The VRF assignment also comports with the currently effective standards PRC-016-0.1 and PRC-022-1.~~comingles multiple activities
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R1	
	Failure to review each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate for Misoperation could, in the planning time frame, 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.~~ Protection System operations reviewed for proper operation by their owner(s) is the first step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. ~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R1			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity identified whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to identify whether ~~or not~~ its Protection System component(s) caused a Misoperation in accordance with Requirement R1.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan.” The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The VSLs appropriately assess the severity of the violation with the failure to perform a review for Misoperation as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R1	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to notify the other owner(s) of a Composite Protection System when the initiating owner determined its Protection System components did not cause a Misoperation or it did not rule out a Misoperation, could in the planning time frame, 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.~~ Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could ~~contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system by creating a gap in analysis.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report:

VRF and VSL Justifications – PRC-004-3, R2	
	This is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A lack of coordination on system protection was one of eight factors common to substantive outages prior to and including the August 14, 2003 Blackout. The initiating entity in the planning time frame is required to notify the other owner(s) of the Composite Protection System component(s) when it determines that (or is unsure whether)its component(s) did not cause a Misoperation or when it is unable to rule out a Misoperation of the Composite Protection System owned by others. This ensures that all owners review their equipment for proper operation which may include checking for proper coordination depending on the circumstances.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards:

VRF and VSL Justifications – PRC-004-3, R2	
	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO~~).~~), which both have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan~~" which both have a VRF of High.~~". This requirement and a VRF assignment of Medium is consistent, for example, with Reliability Standards FAC-008-3 – Facility Ratings, R7 ("…shall provide Facility Ratings (for its solely and jointly owned Facilities…"), MOD-012-0 – Dynamics Data for Modeling and Simulation of the Interconnected Transmission System, R2 ("…shall provide appropriate equipment characteristics and system data…"), ~~and~~ IRO-015-1 – ~~NAME~~Special Protection System Data and Documentation, R1.1 ("…shall make notifications to other Reliability Coordinators of conditions in its Reliability Coordinator Area that may impact other Reliability Coordinator Areas~~.")~~."), and IRO-016-1 – Coordination of Real-time Activities Between Reliability Coordinators, R1 ("…shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.") which all have a VRF of Medium. Other Protection Systems based Reliability Standards such as PRC-005-1b – Transmission and Generation Protection System Maintenance and Testing, R2 ("…shall provide documentation…"), PRC-016-0.1 – Special Protection System Misoperations, R3 ("…that owns an SPS shall provide documentation of the misoperation analyses…"), and PRC-017-0 – Special Protection System Maintenance and Testing, R2 ("…SPS shall provide documentation of the program…) all have a VRF of Lower; however, these requirements involve the administrative reporting to either the Regional Reliability Organization (now Regional Entity) or NERC and not a reliability function like the previously mentioned FAC-008-3 and MOD-012-0 Reliability Standards. As such, this Requirement R2 is assigned a VRF of Medium because it has a reliability need to be communicated to other owners.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs:

VRF and VSL Justifications – PRC-004-3, R2	
	Failure to notify other entities to review each Protection System operation, identify Misoperations, and determine the cause could in the planning time frame, 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.~~ Unresolved Misoperations of Composite Protection Systems owned by others that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. ~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R2			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 120 calendar days and less than or equal to 150 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 150 calendar days and less than or equal to 165 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 165 calendar days and less than or equal to 180 calendar days of the BES interrupting device operation.	The responsible entity notified the other owner(s) of the Protection System component(s) in accordance with Requirement R2, but in more than 180 calendar days of the BES interrupting device operation. OR The responsible entity failed to notify one or more of the other owner(s) of the Protection System component(s) in accordance with Requirement R2.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement is new to the standard and had no previous level of compliance. Other Reliability Standards use a variety of VSLs ranging from a single severe level (i.e., binary), two levels, to four VSL levels. Some use a percentage as the failure of the number entities not notified; however, this would not be practical for this requirement as Composite Protection Systems that are owned by multiple entities is generally limited to one or two owners. The incremental increase in violation is consistent with the NERC Guidelines and is reasonable in consideration of the time periods provided by the Requirement.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.

VRF and VSL Justifications – PRC-004-3, R2	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level 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-004-3, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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.~~ Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. ~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that zone 3 relays increased the severity of the blackout. Reviewing Protection Systems for Misoperation, identifying an unnecessary operation and taking corrective actions would reduce the likelihood of reoccurrence. This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan” which both have a VRF of High. This Requirement R3, to “review” (similar to “analyze”), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 (“…shall analyze its SPS operations and maintain a record of all misoperations…”) and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 (“…shall analyze and document all UVLS operations and Misoperations.”) which both have a VRF of Medium. A VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justifications – PRC-004-3, R3	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure of another Composite Protection System owner to review its component(s) for Misoperation, upon notification, for each BES interrupting device operation caused by a Protection System operation or by manual intervention in response to a Protection System failure to operate could in the planning time frame, 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.~~ Composite Protection System operations reviewed for proper operation by the other owner(s) is an important step in preventing the future severity of disturbances affecting a wider area, or potential equipment damage. ~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justifications – PRC-004-3, R3			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 30 calendar days and less than or equal to 45 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 45 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R3, but was greater than 60 calendar days late. OR The responsible entity failed to identify whether or not a Misoperation of its Protection System component(s) occurred in accordance with Requirement R3.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.		

VRF and VSL Justifications – PRC-004-3, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (DP) and R2 (GO & TO) for the notified Protection System owner. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. A VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to identify the cause(s) of a Misoperation (if not determined in Requirements R1 or R3) could in the planning time frame, 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.~~ An Unidentified cause(s) of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.~~ However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is consistent with Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. The applicable entity must conduct investigative action(s) to determine the cause(s) of a Misoperation, if not determined during the course of a review as proposed in Requirements R1 and R3.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R4	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO~~).~~), which have a VRF of High. The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan~~" which have a VRF of High.~~." This Requirement R4, to perform at least one "investigative action" (similar to "analyze"), comports with Reliability Standards PRC-016-0.1 – Special Protection System Misoperations, R1 ("…shall analyze its SPS operations and maintain a record of all misoperations…") and PRC-022-1 – Under-Voltage Load Shedding Program Performance, R1 ("…shall analyze and document all UVLS operations and Misoperations.") which both have a VRF of Medium. A VRF of Medium is not inadvertently lowering the current VRF of High in the former PRC-004-2.1a, Requirements R1 or R3, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous. This VRF of Medium comports with the VRF assignment of Medium for PRC-004-3, Requirements R1 and R3, which will generally reveal the cause(s) of an identified Misoperation.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to identify the cause(s) of a Misoperation could in the planning time frame, 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.~~

VRF and VSL Justifications – PRC-004-3, R4			
	Unidentified causes of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. ~~However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~		
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity performed at least one investigative action in accordance with Requirement R4, but was less than or equal to one calendar quarter late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than one calendar quarter and less than or equal to two calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was greater than two calendar quarters and less than or equal to three calendar quarters late.	The responsible entity performed at least one investigative action in accordance with Requirement R4, but was more than three calendar quarters late. OR The responsible entity failed to perform investigative action(s) in accordance with Requirement R4.

VRF and VSL Justifications – PRC-004-3, R4	
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. The VSL is entity size-neutral because performance is event-driven and not by individual assets.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. This VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. This VSLs appropriately assess the severity of the violation with the failure to perform investigative actions as Severe.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This 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-004-3, R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4 Violation Severity Level 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-004-3, R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to develop a CAP for a Misoperation with an identified cause could in the planning time frame, 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.~~ An unresolved cause of a Misoperation or failing to consider other locations with similar Protection System components could ~~contribute~~affect the ~~severity~~electrical state or capability of ~~future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to~~the bulk electric system~~ instability, separation~~, or ~~cascading failures~~the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the development of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.

VRF and VSL Justifications – PRC-004-3, R5	
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have a VRF of High. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 ("…shall take corrective actions to avoid future Misoperations"), PRC-022-1, R1.5 ("For any Misoperation, a Corrective Action Plan…"), FAC-003, R5 ("…Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management") all three of which have a VRF of Medium.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to develop a CAP for a Misoperation with an identified cause or failing to consider other locations with similar components could in the planning time frame, 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.~~ An unresolved cause of a Misoperation could ~~contribute~~affect the ~~severity~~electrical state or capability of ~~future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to~~the bulk electric system~~ instability, separation~~, or ~~cascading failures~~the ability to effectively monitor, control, or restore the bulk electric system if the same condition resulted in a future Misoperation.

VRF and VSL Justifications – PRC-004-3, R5			
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.		
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation. OR	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 80 calendar days and less than or equal to 90 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed a CAP, or explained in a declaration in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop a CAP or explain in a declaration in accordance with Requirement R5. OR

VRF and VSL Justifications – PRC-004-3, R5			
The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 60 calendar days and less than or equal to 70 calendar days of first identifying a cause of the Misoperation.	The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 70 calendar days and less than or equal to 80 calendar days of first identifying a cause of the Misoperation.		The responsible entity developed an evaluation in accordance with Requirement R5, but in more than 90 calendar days of first identifying a cause of the Misoperation. OR The responsible entity failed to develop an evaluation in accordance with Requirement R5.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—There is an incremental aspect to the VSL for tardiness and a binary aspect for failure. Varying VSLs are provided for the omission of the evaluation when developing the Corrective Action Plan and for failure to develop the evaluation.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan" which have varying VSLs. This VSL does not lower the current level of compliance because the former VSL in PRC-004-2.1a was comingled with the other activities. This Requirement has a Severe VSL for failure to develop the CAP with the other VSLs being based on tardiness of the development.		

VRF and VSL Justifications – PRC-004-3, R5	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. Guideline 2b: This VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	This VSL uses similar terminology to that used in the associated requirement, and is therefore consistent with this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justifications – PRC-004-3, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justification – PRC-004-3, R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A Violation Risk Factor of Medium is consistent with the NERC VRF Guidelines. Failure to implement a CAP for a Misoperation with an identified cause could in the planning time frame, 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.~~ An uncorrected cause of a Misoperation as a result of not implementing a Corrective Action Plan, could ~~contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system since the condition could occur again.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis resulted in entities performing corrective actions; however, there were no negative reliability outcomes concerning the implementation of a Corrective Action Plan (CAP) associated with Protection Systems.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: This requirement has a single reliability activity associated with the reliability objective and no sub-Requirement(s) which allows a single VRF to be assigned; therefore no conflict(s) exist.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2.1a, R1 (TO & DP) and R2 (GO~~).~~),which both have a VRF of High. The three performance components (paraphrased) are “analyze Protection System Misoperations,” “develop a Correction Action Plan,” and “implement a Corrective Action Plan~~” which both have a VRF of High.~~”. This requirement is consistent with Reliability Standards PRC-016-0.1, R2 (“…shall take corrective actions to avoid future misoperations.”) and PRC-022-1, R1.5 (“For any Misoperation, a Corrective Action Plan…”) which both have a VRF of Medium. The proposed VRF of Medium does not inadvertently lower the current VRF of High in the former PRC-004-2.1a, Requirements R1 and R2, because this Requirement now provides a clear and concise single reliability activity whereas the former Requirement contained multiple activities and is ambiguous.

VRF and VSL Justification – PRC-004-3, R6	
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: Failure to implement a Corrective Action Plan for a Misoperation with an identified cause could in the planning time frame, 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.~~ An uncorrected cause of a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage.~~ However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.~~
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle reliability objectives of differing risk; therefore, the assigned VRF of Medium is consistent.

VRF and VSL Justification – PRC-004-3, R6			
Proposed VSL			
Lower	**Moderate**	**High**	**Severe**
The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R6.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R6.
NERC VSL Guidelines	Meets NERC's VSL Guidelines—The VSLs cover aspects of this Requirement that are not equal in importance and performance.		
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 3- Consistency among Reliability Standards: This requirement replaces one of the three performance components of PRC-004-2a, R1 (TO & DP) and R2 (GO). The three performance components (paraphrased) are "analyze Protection System Misoperations," "develop a Correction Action Plan," and "implement a Corrective Action Plan." The VSLs are based on the three components and not individually as presented in the proposed PRC-004-3 standard. The proposed VSL does not lower the current level of compliance because the former VSL was comingled with the other activities. The proposed Requirement is a Severe VSL for failure to implement the CAP with the Lower VSL being based on the failure of updating the CAP when actions or timetables change which is administrative in nature.		

VRF and VSL Justification – PRC-004-3, R6	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: This requirement is not binary; therefore, this criterion does not apply. 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.
FERC VSL G3 Violation Severity Level 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 this Requirement.
FERC VSL G4	The VSL is based on a single violation and not cumulative violations.

VRF and VSL Justification – PRC-004-3, R6	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

Table of Issues and Directives

Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1460.	For the reasons stated in the NOPR, the Commission will not approve or remand PRC-003-1. (For reference) P 1458. In the NOPR, the Commission identified PRC-003-1 as a fill-in-the-blank standard. The NOPR stated that because the regional procedures had not been submitted, the Commission proposed not to approve or remand PRC-003-1 until the ERO submitted the additional information.	PRC-004-3	PRC-003-1 will be retired and replaced by PRC-004-3.

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1461.	We agree with APPA that the ERO should consider whether greater consistency can be achieved in this Reliability Standard. In Order No. 672, the Commission also encouraged greater uniformity in the development of Reliability Standards. Consistent with that goal, the Commission directs the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC-003-1 to provide missing information needed for the Commission to act on this Reliability Standard. (For reference) P 1459. APPA agrees with the Commission's proposed course of action. It states that there are significant and substantive differences between regional procedures due to the characteristics of various regional grids and industry structures. Further it suggests that NERC and the Regional Entities consider whether they can attain greater consistency on an Interconnection-wide basis in completing this Reliability Standard.	NERC Rules of Procedure, Section 1600 Request for Data or Information.	PRC-003-1 will be retired and replaced by PRC-004-3. The responsibility to address all aspects of a Protection System Misoperation is assigned to the owner(s) of the Protection System(s) - the Transmission Owner, Generation Owner, and Distribution Provider. Additionally, further consistency has been achieved by specifying the data reporting requirements for periodic Misoperations reporting based on a continent-wide template. All reporting of Misoperations will be done through a data request according to the NERC Rules of Procedures, Section 1600, Request for Data or Information instead of having PRC-004-3 specify an administrative reporting requirement.

Table of Issues and Directives Associated with PRC-003-1			
Source	**Issue or Directive Language (including Para. #)**	**Section and/or Requirement(s)**	**Consideration of Issue or Directive**
FERC Order No. 693, P 1469 (first directive only)	We direct the ERO to consider ISO-NE's suggestion that LSEs and transmission operators should be included in the applicability section, in the Reliability Standards development process as it modifies PRC-004-1. (For reference) P 1466. ISO-NE further requests the Commission to direct NERC to modify PRC-004-1 to include LSEs and transmission operators in the applicability section. It states that based on current practice in the ISO-NE balancing area, transmission operators, transmission owners, LSEs and distribution providers may individually or jointly own and operate a protection system. It therefore suggests that transmission operators and LSEs should also be included in the applicability section. ISO-NE provides the same suggestion with regard to PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0 and PRC-021-1.	PRC-004-3 all Requirements.	PRC-004-2.1a will be retired and replaced by PRC-004-3.The Transmission Owner, Generator Owner, and Distribution Provider own the BES Protection Systems. The owners of BES Protection Systems have been assigned responsibility for this standard.

Standards Announcement

Project 2010-05.1 Protection System (Misoperations)
PRC-004-3

Final Ballot Now Open through August 7, 2014

Now Available

A final ballot for **PRC-004-3 – Protection System Misoperation Identification and Correction** and is open through **8 p.m. Eastern on Thursday, August 7, 2014**.

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 ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member previously cast a vote, but does not participate in the final ballot, the member's vote cast in the previous ballot will be carried over as their vote 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

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 Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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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 Updated

Project 2010-05.1 Protection System (Misoperations) PRC-004-3

Final Ballot Results

Now Available

A final ballot for **PRC-004-3 – Protection System Misoperation Identification and Correction** concluded **8 p.m. Eastern on Thursday, August 7, 2014.**

The standard achieved a quorum and 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.

Standard	Quorum / Approval
PRC-004-3	77.94% / 79.75%

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 information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller (via email), Standards Development Administrator, or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2010-05.1 Protection Systems: Misoperationsl
Ballot Period:	7/29/2014 - 8/7/2014
Ballot Type:	Final
Total # Votes:	325
Total Ballot Pool:	417
Quorum:	**77.94 % The Quorum has been reached**
Weighted Segment Vote:	79.75 % (Updated)
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	110	1	73	0.83	15	0.17	0	5	17
2 - Segment 2	9	0.5	3	0.3	2	0.2	0	3	1
3 - Segment 3	102	1	54	0.806	13	0.194	0	10	25
4 - Segment 4	33	1	17	0.773	5	0.227	0	2	9
5 - Segment 5	92	1	46	0.754	15	0.246	0	10	21
6 - Segment 6	52	1	31	0.795	8	0.205	0	3	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	10	0.3	3	0.3	0	0	0	0	7
9 - Segment 9	2	0	0	0	0	0	0	0	2

10 - Segment 10	7	0.7	6	0.6	1	0.1	0	0	0
Totals	**417**	**6.5**	**233**	**5.158**	**59**	**1.342**	**0**	**33**	**92**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Abstain	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Consumers Power Inc.	Stuart Sloan		
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Abstain	
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	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted E Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
				SUPPORTS

1	Lakeland Electric	Larry E Watt	Negative	THIRD PARTY COMMENTS
1	Lee County Electric Cooperative	John W Delucca		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Joe D Petaski		
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Abstain	
1	NStar Gas and Electric	John Robertson		
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
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	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom		
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Abstain	

1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Negative	COMMENT RECEIVED
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs		
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blachly-Lane Electric Co-op	Bud Tracy		
3	Blue Ridge Electric	James L Layton	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Cooperative, Inc. (Redmond, Oregon)	Dave Markham		
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Palo Alto	Eric R Scott		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	Clearwater Power Co.	Dave Hagen		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	Consumers Power Inc.	Roman Gillen		
3	Coos-Curry Electric Cooperative, Inc	Roger Meader		
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke	Abstain	
3	Entergy	Joel T Plessinger		
3	Fall River Rural Electric Cooperative	Bryan Case		
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Flathead Electric Cooperative	John M Goroski	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Abstain	
3	JEA	Garry Baker	Negative	COMMENT RECEIVED
3	KAMO Electric Cooperative	Theodore J Hilmes	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	

3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lane Electric Cooperative, Inc.	Rick Crinklaw		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris		
3	Northern Lights Inc.	Jon Shelby		
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Old Dominion Electric Coop.	Bill Watson		
3	Orange and Rockland Utilities, Inc.	David Burke		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Pacific Northwest Generating Cooperative	Rick Paschall		
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	COMMENT RECEIVED
3	Raft River Rural Electric Cooperative	Heber Carpenter		
3	Rutherford EMC	Thomas Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
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	Affirmative	
3	Southern California Edison Company	David B Coher	Negative	SUPPORTS THIRD PARTY COMMENTS - Patrick Farrell
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Negative	NO COMMENT RECEIVED
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos		
3	Umatilla Electric Cooperative	Steve Eldrige		
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	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Buckeye Power, Inc.	Manmohan K Sachdeva		
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		

4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
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	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Integrys Energy Group, Inc.	Christopher Plante	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Pacific Northwest Generating Cooperative	Aleka K Scott		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
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	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill		
4	West Oregon Electric Cooperative, Inc.	Marc M Farmer		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
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	Negative	
5	Bridgeport Energy	Cleyton Tewksbury		
5	Caithness Long Island, LLC	Jason M Moore		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Cogentrix Energy, Inc.	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Detroit Edison Company	Christy Wicke	Abstain	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	Edison Mission Marketing & Trading Inc.	Brenda J Frazer		
5	El Paso Electric Company	David Hawkins		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman		

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	Negative	
5	Imperial Irrigation District	Marcela Y Caballero		
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
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
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	
5	Northern Indiana Public Service Co.	William O. Thompson		
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer		
5	Platte River Power Authority	Roland Thiel	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	
5	Proven Compliance Solutions	Mitchell E Needham		
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	COMMENT RECEIVED
5	TransAlta Corporation	Rebbekka McFadden		
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	Turlock Irrigation District	Marty Rojas		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	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	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto		
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS of FMPA.
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Imperial Irrigation District	Cathy Bretz		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Luminant Energy	Brad Jones		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried		
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
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	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Negative	SUPPORTS THIRD PARTY COMMENTS- Patrick Farrell
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Turlock Irrigation District	Amy Petersen		
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Edward C Stein		
8		James A Maenner		

8	JDRJC Associates	Jim Cyrulewski		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan		
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
9	Oregon Public Utility Commission	Jerome Murray		
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Legal and Privacy : 404.446.2560 voice : 404.467.0474 fax : 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit H

Request for Data or Information: Protection System Misoperation Data Collection

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

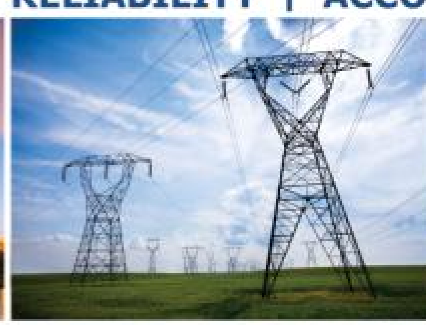
Request for Data or Information

Protection System Misoperation Data Collection

August 14, 2014

RELIABILITY | ACCOUNTABILITY



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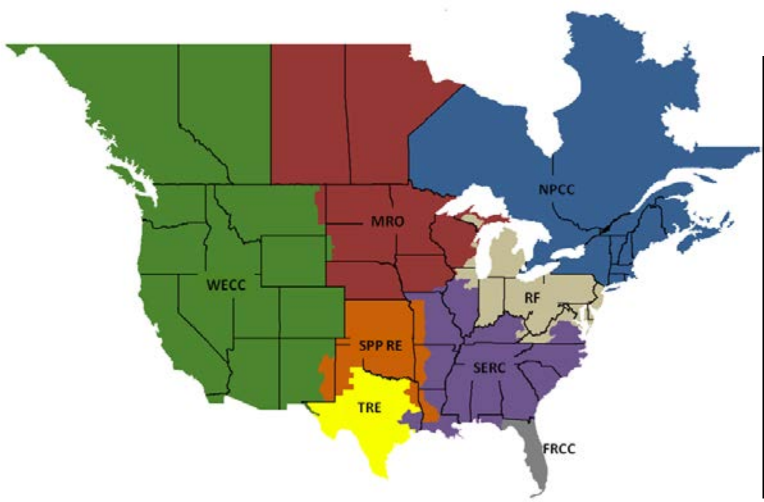
Preface

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 and Survey Scope

In accordance with Section 1600 of the NERC *Rules of Procedure*,[1] NERC may request data or information ("Data Request") necessary in order to meet its obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d)[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations.

Standard development Project 2010-05.1 – Phase 1: Protection Systems (Misoperations[3]) involves the revision of Reliability Standard PRC-004-2.1a (Analysis and Mitigation of Transmission and Generation Protection System Misoperations). The revised standard, PRC-004-3 (Protection System Misoperation Identification and Correction), will combine Reliability Standard PRC-003-1 – Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems and Reliability Standard PRC-004-2.1a.

The Standards Authorization Request in Project 2010-05.1, which sets the scope of work for combining Reliability Standards PRC-003-1 and PRC-004-2.1a, includes instructions to address the following in Project 2010-05.1:

- Clarify the definition of "Misoperation;"
- Establish a consistent metric for measuring Protection System performance with uniform applicability;
- Clarify reporting requirements and processes;
- Review all Faults or Protection System operations on the Bulk Electric System ("BES") to identify those that are BES Protection System Misoperations;
- Analyze BES Protection System Misoperations to determine cause(s); and
- Develop and implement Corrective Action Plans to address the causes of BES Protection System Misoperations.

The Protection System Misoperations Standard Drafting Team (SDT) in Project 2010-05.1 has removed the data reporting obligation included in Reliability Standard PRC-004-2.1a[4] from the revised standard and recommended that NERC request the data required for performance analysis purposes pursuant to Section 1600 of the NERC *Rules of Procedure*. The revised Reliability Standard PRC-004-3 will continue to require retention of data or evidence of compliance with the standard, but will no longer require periodic reporting of that information. Periodic, quarterly submittals of Misoperation data will be associated with reporting under this Section 1600 Data Request.

The purpose of this Data Request is to continue consistent reporting of Misoperation data to NERC through a standardized template for performance analysis. NERC will analyze the data to:

- Develop meaningful metrics to assess Protection System performance;
- Identify trends in Protection System performance that negatively impact reliability;
- Identify remediation techniques to reduce the rate of occurrence and severity of Misoperations;

---

[1] NERC's *Rules of Procedure* are available at: http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[2] 18 C.F.R. § 39.2(d) (2014).

[3] "Misoperation" is a defined term in the NERC *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), *available at*: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[4] Requirement R3 of PRC-004-2.1a requires Transmission Owners, any Distribution Providers that own a transmission Protection System, and Generator Owners to provide to its Regional Entity documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

- Provide focused assistance to entities in need of guidance; and
- Publicize lessons learned to the industry.

Monitoring, analyzing, and tracking trends in Protection System Misoperations are critical to improve BES reliability. Historically, Protection System Misoperations have exacerbated the severity of most cascading power outages. For example, Protection System Misoperations played a significant role in expanding the impacts of the August 14, 2003 Northeast blackout.[5] In the 2012 State of Reliability report,[6] Misoperations were identified as one of the top risks to reliability. Additionally, Protection System Misoperations were cited as being one of the primary risk factors in the 2013 State of Reliability report.[7] Following the recommendations in the 2012 State of Reliability report, the Protection System Misoperations Task Force was formed to review Misoperations and provide recommendations for reducing Misoperations. The task force analyzed the top three causes of Misoperations between the first quarter of 2011 and the second quarter of 2012 and developed suggestions to reduce Misoperations. This analysis relied heavily on the data collected under Reliability Standard PRC-004-002.1a. Absent this information, the analysis would not have been possible. The 2014 State of Reliability report continued to identify Protection System Misoperations as a significant contributor to automatic transmission outage severity. The report recommended completion of the development of PRC-004-3 as part of the solution to address Protection System Misoperations.

Further, Misoperation data collection provides several benefits to BES reliability and supports NERC's mission of ensuring the reliability of the BPS in North America. The proposed Data Request will make available the information necessary for NERC to provide high value risk analysis. This data will also allow NERC to identify areas for improvement in Misoperation rates through quantitative data analysis. For these reasons, NERC is proposing to continue collection of the data immediately upon the retirement of the data reporting obligation in Reliability Standard PRC-004-2.1a.

NERC posted a proposed Data Request in accordance with the requirements of Section 1602 of the NERC *Rules of Procedure* for a 45-day public comment period. On July 23, 2013, NERC provided this proposed Data Request to FERC for review as required by Section 1602 of the NERC *Rules of Procedure*. After consideration of comments received, NERC made revisions to the proposed Data Request. If approved by the Board as required by Section 1602 of the NERC *Rules of Procedure,* this Data Request will become mandatory concurrently with the retirement of Reliability Standard PRC-004-2.1a which presently contains the data reporting obligation.

[5] *U.S.-Canada Power System Outage Task Force Study: August 14th Blackout: Causes and Recommendations* at 109, available at: https://reports.energy.gov/BlackoutFinal-Web.pdf

[6] *2012 State of Reliability*, available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2012_SOR.pdf

[7] *State of Reliability 2013*, available at: http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf

NERC Contact Information

The Data Request must be completed in electronic format. Should the submitting entity experience any issues with submitting its data, contact Charles Aderholdt via email at Charles.Aderholdt@nerc.net or by telephone at (404) 446-2569. If the respondent believes that any of the responses to this survey should remain confidential, contact the project manager directly for further instructions.

Official correspondence may be mailed to:

NERC – Misoperations
C/O Charles Aderholdt
3353 Peachtree Road, Suite 600, North Tower
Atlanta, GA 08540

Authority

Under Section 215 of the Federal Power Act (16 U.S.C. § 824o), Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. NERC was certified as the ERO on July 20, 2006. NERC's authority for issuing this survey is derived from Section 215 of the Federal Power Act, and from the following sources:

Section 39.2(d) of the FERC's regulations (18 C.F.R. §39.2(d)) provides:

> Each user, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii) shall provide the Commission, the Electric Reliability Organization and the applicable Regional Entity such information as is necessary to implement section 215 of the Federal Power Act as determined by the Commission and set out in the Rules of the Electric Reliability Organization and each applicable Regional Entity. The Electric Reliability Organization and each Regional Entity shall provide the Commission such information as is necessary to implement section 215 of the Federal Power Act.

Section 1600 of NERC's *Rules of Procedure* provides:

> ***1601. Scope of a NERC or Regional Entity Request for Data or Information***
>
> *Within the United States, NERC and Regional Entities may request data or information that is necessary to meet their obligations under Section 215 of the Federal Power Act, as authorized by Section 39.2(d) of the Commission's regulations, 18 C.F.R. § 39.2(d). In other jurisdictions, NERC and Regional Entities may request comparable data or information, using such authority as may exist pursuant to these rules and as may be granted by ERO governmental authorities in those other jurisdictions. The provisions of Section 1600 shall not apply to requirements contained in any Reliability Standard to provide data or information; the requirements in the Reliability Standards govern. The provisions of Section 1600 shall also not apply to data or information requested in connection with a compliance or enforcement action under Section 215 of the Federal Power Act, Section 400 of these Rules of Procedure, or any procedures adopted pursuant to those authorities, in which case the Rules of Procedure applicable to the production of data or information for compliance and enforcement actions shall apply.*

1602. Procedure for Authorizing a NERC Request for Data or Information

1. *NERC shall provide a proposed request for data or information or a proposed modification to a previously-authorized request, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability at least twenty-one (21) days prior to initially posting the request or modification for public comment. Submission of the proposed request or modification to the Office of Electric Reliability is for the information of the Commission. NERC is not required to receive any approval from the Commission prior to posting the proposed request or modification for public comment in accordance with paragraph 1602.2 or issuing the request or modification to reporting entities following approval by the Board.*

2. *NERC shall post a proposed request for data or information or a proposed modification to a previously authorized request for data or information for a forty-five (45) day public comment period.*

2.1. *A proposed request for data or information shall contain, at a minimum, the following information: (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; (ii) a description of how the data or information will be collected and validated; (iii) a description of the entities (by functional class and jurisdiction) that will be required to provide the data or information ("reporting entities"); (iv) the schedule or due date for the data or information; (v) a description of any restrictions on disseminating the data or information (e.g., "confidential," "critical energy infrastructure information," "aggregating" or "identity masking"); and (vi) an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request.*

2.2. *A proposed modification to a previously authorized request for data or information shall explain (i) the nature of the modifications; (ii) an estimate of the burden imposed on the reporting entities to accommodate the modified data or information request, and (iii) any other items from paragraph 1.1 that require updating as a result of the modifications.*

3. *After the close of the comment period, NERC shall make such revisions to the proposed request for data or information as are appropriate in light of the comments. NERC shall submit the proposed request for data or information, as revised, along with the comments received, NERC's evaluation of the comments, and recommendations, to the Board.*

4. *In acting on the proposed request for data or information, the Board may authorize NERC to issue it, modify it, or remand it for further consideration.*

5. *NERC may make minor changes to an authorized request for data or information without Board approval. However, if a reporting entity objects to NERC in writing to such changes within 21 days of issuance of the modified request, such changes shall require Board approval before they are implemented.*

6. *Authorization of a request for data or information shall be final unless, within thirty (30) days of the decision by the Board, an affected party appeals the authorization under this Section 1600 to the ERO governmental authority.*

1603. Owners, Operators, and Users to Comply

Owners, operators, and users of the BPS registered on the NERC Compliance Registry shall comply with authorized requests for data and information. In the event a reporting entity within the United States fails to comply with an authorized request for data or information under Section 1600, NERC may request the Commission to exercise its enforcement authority to require the reporting entity to comply with the request for data or information and for other appropriate enforcement action by the Commission. NERC will make any request for the Commission to enforce a request for data or information through a non-public submission to the Commission's enforcement staff.

1605. Confidentiality

If the approved data or information request includes a statement under Section 1602.1.1(v) that the requested data or information will be held confidential or treated as Critical Energy Infrastructure Information, then the applicable provisions of Section 1500 will apply without further action by a Submitting Entity. A Submitting Entity may designate any other data or information as Confidential Information pursuant to the provisions of Section 1500, and NERC or the Regional Entity shall treat that data or information in accordance with Section 1500. NERC or a Regional Entity may utilize additional protective procedures for handling particular requests for data or information as may be necessary under the circumstances.

1606. Expedited Procedures for Requesting Time-Sensitive Data or Information

1. *In the event NERC or a Regional Entity must obtain data or information by a date or within a time period that does not permit adherence to the time periods specified in Section 1602, the procedures specified in Section 1606 may be used to obtain the data or information. Without limiting the circumstances in which the procedures in Section 1606 may be used, such circumstances include situations in which it is necessary to obtain the data or information (in order to evaluate a threat to the reliability or security of the BPS, or to comply with a directive in an order issued by the Commission or by another Applicable Governmental Authority) within a shorter time period than possible under Section 1602. The procedures specified in Section 1606 may only be used if authorized by Board prior to activation of such procedures.*

2. *Prior to posting a proposed request for data or information, or a modification to a previously-authorized request, for public comment under Section 1606, NERC shall provide the proposed request or modification, including the information specified in paragraph 1602.2.1 or 1602.2.2 as applicable, to the Commission's Office of Electric Reliability. The submission to the Commission's Office of Electric Reliability shall also include an explanation of why it is necessary to use the*

expedited procedures of Section 1606 to obtain the data or information. The submission shall be made to the Commission's Office of Electric Reliability as far in advance, up to twenty-one (21) days, of the posting of the proposed request or modification for public comments as is reasonably possible under the circumstances, but in no event less than two (2) days in advance of the public posting of the proposed request or modification.

3. *NERC shall post the proposed request for data or information or proposed modification to a previously-authorized request for data or information for a public comment period that is reasonable in duration given the circumstances, but in no event shorter than five (5) days. The proposed request for data or information or proposed modification to a previously-authorized request for data or information shall include the information specified in Section 1602.2.1 or 1602.2.2, as applicable, and shall also include an explanation of why it is necessary to use the expedited procedures of Section 1606 to obtain the data or information.*

4. *The provisions of Sections 1602.3, 1602.4, 1602.5 and 1602.6 shall be applicable to a request for data or information or modification to a previously-authorized request for data or information developed and issued pursuant to Section 1606, except that (a) if NERC makes minor changes to an authorized request for data or information without Board approval, such changes shall require Board approval if a Reporting Entity objects to NERC in writing to such changes within five (5) days of issuance of the modified request; and (b) authorization of the request for data or information shall be final unless an affected party appeals the authorization of the request by the Board to the Applicable Governmental Authority within five (5) days following the decision of the Board authorizing the request, which decision shall be promptly posted on NERC's website.*

Data Request

Data Description

Effective immediately upon the retirement of Reliability Standard PRC-004-2.1a, data included in Table 1 below will be collected quarterly on a per-entity basis. The data will be collected for Misoperations, as defined in the NERC Glossary, which are identified pursuant to Reliability Standard PRC-004. In cases where multiple entities own a Protection System, the entity responsible for identifying whether its Protection System Component(s) caused a Misoperation pursuant to PRC-004 will report Misoperation data under this Data Request.

Table 1: Protection System Misoperation Fields	
Tab 1 – Operation Summary	
Field Name	**Field Description**
Data Submission Year	The calendar year for which the operation data is reported.
Data Submission Quarter	The calendar quarter for which the operation data is reported.
Regional Entity Name	The entity's Regional Entity. If the entity is registered in multiple Regional Entities, the Regional Entity area where the Misoperation occurred.
Functional Entity NERC ID	The entity's NERC compliance registry number. If the entity does not have a NERC compliance registry number, the company name.
Total Protection System Operations by Voltage Class	The total number of Protection System operations by system voltage based on the definition in the reporting template.
Tab 2 – Misoperation Entry Form	
Field Name	**Field Description**
Misoperation ID	An entity-specific Misoperation identifier.
Regional Entity	The entity's Regional Entity. If the entity is registered in multiple Regional Entities, the Regional Entity area where the Misoperation occurred.
NERC ID	The entity's NERC compliance registry number. If the entity does not have a NERC compliance registry number, the company name.
Misoperation Date	The date of the Misoperation.
Misoperation Time	The time of the Misoperation.
Time Zone	The time zone in which the Misoperation occurred.
Facility Name (Location of Misoperation)	The name of the facility (i.e., substation or generating station) where the Misoperation occurred.
Equipment Name (protected by Protection System that Misoperated)	The name of the generator, transmission line, transformer, bus, or equipment protected by the Protection System that misoperated.
Equipment Type	The type of equipment being protected (e.g., line, transformer, etc.).
Facility Voltage	The system voltage of the protected Element. If the Element is a transformer, the high-side voltage. If the Element is a generator, the GSU transformer high-side voltage.

Table 1: Protection System Misoperation Fields	
Equipment Removed from Service (Permanently or Temporarily) as the result of the Misoperation	The names of the equipment becoming unavailable due to the Misoperation (Equipment refers only to circuits, transformers, buses, but not breakers UNLESS the breaker is the only Element). Breaker should be used only if a single breaker tripped and did not disconnect any Element at one of its terminals (one breaker in a multiple breaker protected line, bus tie breaker, etc.).
Event Description	A brief description of the event including: 1. Initiating event: include a description of any internal or external fault causes, any abnormal system conditions which may have contributed to the Misoperation, or state that the Misoperation occurred under normal operating conditions. 2. Facilities involved on which Protection Systems operated correctly and/or incorrectly concurrent with the Misoperation. 3. Component(s) of the Protection System(s) that failed and/or did not function correctly. 4. Detailed description of root causes determined by completed Corrective Action Plans.
Misoperation Category (as defined in the reporting template)	The category of the Misoperation: • Failure to Trip – During Fault • Failure to Trip – Other Than Fault • Slow Trip – During Fault • Slow Trip – Other Than Fault • Unnecessary Trip – During Fault • Unnecessary Trip – Other Than Fault
Cause(s) of Misoperation (as defined in the reporting template)	The primary cause of the Misoperation: • AC system • As-left personnel error • Communication failures • DC system • Incorrect settings • Logic errors • Design errors • Relay failures/malfunctions • Unknown/unexplainable • Other/Explainable
Protection Systems/Components that Misoperated	Information on the Protection Systems/Components that Misoperated. If the “Cause of Misoperation” is “Relay failures/malfunctions,” “Incorrect settings,” “Logic errors,” or “Design errors,” and the cause is associated with a relay, this field is used to identify the relay models (types) and protection schemes.
Relay Technology	If the Cause of Misoperation is “Relay failures/malfunctions,” “Incorrect settings,” “Logic errors,” or “Design errors”, this field is used to identify the relay technology installed. • Electromechanical • Solid State • Microprocessor

Table 1: Protection System Misoperation Fields	
Is this a Transmission Availability Data System (TADS) reportable event?	Whether the Misoperation involved the automatic outage of a TADS-reportable transmission Element. (Reporting by Transmission Owners only.)
Select one or more TADS "Element IDs" for any TADS reportable Elements outaged in the Misoperation.	If a TADS reportable Element was outaged due to the Misoperation, the Element(s) in a comma-separated list. (Reporting by Transmission Owners only.)
Is this a Generation Availability Data System (GADS) reportable event?	Whether the Misoperation involved the automatic outage of a GADS-reportable Element. (Reporting by Generator Owners only.)
If the Misoperation caused a generator forced outage, select one or more Generation Availability Data System (GADS) "Unit IDs" for any GADS reportable Elements outaged in the Misoperation.	If a GADS reportable Element was outaged due to the Misoperation, the Element(s) in a comma-separated list. (Reporting by Generator Owners only.)
Analysis and Corrective Action Status	The status, selected from a drop-down list.
Corrective Action Plan	Identification of the corrective actions. “None” if, in place of a CAP, a declaration was made stating no further corrective actions will be taken.
Corrective Action Plan Target Completion Date	If corrective actions are not complete, an estimate of when they will be complete.
Actual Completion Date	If corrective actions are complete, the actual completion date.
Reported By	The person who filled out the report.
Reporter’s Telephone Number	The reporting person's phone number.
Reporter’s Email Address	The e-mail address of the reporter.
Date Reported	The report date.
Additional Contact Name (Optional)	An additional contact with knowledge of the data.
Additional Contact’s Phone Number (Optional)	If entering an additional contact, the person's phone number.
Additional Contact’s Email Address (Optional)	If entering an additional contact, the person's email.

There are several differences between the data fields used in previous reporting and the proposed data fields. These differences are summarized in Table 2 below.

Table 2: Changes to Misoperation Data Fields	
Field Name	**Field Description**
Misoperation Category	The Failure to Trip and Slow Trip categories have been divided into four categories by splitting each into “During Fault” and “Other than Fault” categories, consistent with the revised Misoperation definition.

Table 2: Changes to Misoperation Data Fields	
Field Name	**Field Description**
Cause(s) of Misoperation	The “Incorrect settings/logic/design errors” cause has been separated into three causes: “Incorrect settings”, “Logic errors”, and “Design errors”.
Is this a Generation Availability Data System (GADS) reportable event?	A field has been added to identify whether the Misoperation involved the automatic outage of a GADS reportable Element.
If the Misoperation caused a generator forced outage, select one or more Generation Availability Data System (GADS) "Unit IDs" for any GADS reportable Elements outaged in the Misoperation.	A field has been added to identify the GADS reportable Elements outaged.

Use of Data

NERC will continue to use the Misoperation information and Protection System operation information to develop statistics regarding the Misoperation rates for the BES. Collection of the total Protection System operations facilitates normalization to account for differences among Registered Entities (e.g., location, climate, size, density, protection schemes used). The Misoperation rate metric can be used to gauge the performance of BES Protection Systems for both generation and transmission Elements. The relative percentage indicates the relative performance of Protection System operations, specifically Protection System Misoperations as a ratio of total Protection System operations. Without knowledge of the Misoperation rates across NERC, normalized measurement of Misoperation reduction will not be possible. In addition, NERC and the Regional Entities will analyze the raw data to identify trends in Protection System Misoperations. Finally, the Misoperation data will be used to support statistical analysis of risks to the BES.

Section 215(g) of the Federal Power Act requires NERC to make periodic assessments on the reliability of the BPS in North America. This Data Request will provide NERC the data necessary to make periodic risk-based assessments to evaluate BPS reliability and provide for continuous analysis of performance and reliability risk. A better understanding of Protection System Misoperations will allow NERC to develop effective requirements to address one of the top risks to the BES.

Entities Required to Comply

The submission of Protection System Misoperation data is mandatory for all U.S. Transmission Owners, Generator Owners, and Distribution Providers who are on the NERC Compliance Registry. Non-U.S. Transmission Owners, Generator Owners, and Distribution Providers should provide data in accordance with the legislation, laws, regulations, rules or orders of their Applicable Governmental Authority. Non-U.S. Transmission Owners, Generator Owners, and Distribution Providers are strongly encouraged to provide the requested data to ensure the completeness of the data collected for analysis.

Scheduling and Reporting

Entities will report data on a quarterly basis. The first reporting period under the Data Request will be the quarter beginning on the first day of the first calendar quarter that is nine (9) months after the date that the PRC-004-3 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 first reporting period under the Data Request will be the quarter beginning on first day of the first calendar quarter that is nine (9) months after the date the Data Request is approved by the Board or as otherwise provided for in that jurisdiction. The deadline for reporting will be 60 days after the end of each quarter.

The reporting schedule is intended to prevent any gap or overlap with reporting that is required pursuant to PRC-004-2.1a. As a result, data for the last quarter occurring prior to retirement of PRC-004-2.1a will be reported under the Data Request. This transition is necessary because the reporting deadline for one period during transition will occur when PRC-004-2.1a is no longer subject to enforcement.

The data will be manually entered or bulk uploaded by Transmission Owners, Generator Owners, and Distribution Providers that own a BES Protection System into the Misoperation module of the webTADS system. After the software checks for errors, a review period will be provided for Regional Entities to review data submitted by the entities in their Region. The Regional Entities will review and sign-off on the data prior to review by NERC. Subsequent to Regional Entity review, NERC will further validate the data and use the data as described above. A final template to be used for bulk uploads is available at: http://www.nerc.com/pa/RAPA/ProctectionSystemMisoperations/Section_1600_Misoperations_Final_Template.xlsx. Data will be bulk uploaded or entered manually through a graphical user interface using the same fields.

Dissemination of Data

NERC's treatment of confidential information is governed by Section 1500 of NERC's *Rules of Procedure* and other agreements with Applicable Governmental Authorities. Individual Misoperation reports are considered confidential. Aggregated Misoperation information is considered public information. However, aggregated Misoperation data public reports will not inadvertently release confidential information by the display of regional or NERC information from which an entity's confidential information could be ascertained.

Burden to Entities

Because entities have been reporting similar data since 2011, there is minimal additional burden for this Data Request. All eight Regional Entities already collect this, or very similar, information using a common template. Reporting Entities are already reporting Misoperations data under the regional procedures as required in Reliability Standard PRC-004-2.1a and minimal changes should be necessary to comply with this Data Request.

Exhibit I

Standard Drafting Team Roster

Team Roster

Project 2010-05.1 Protection System (Misoperations)

	Participant	Entity
Chair	Mark Kuras	PJM Interconnection, LLC
Member	Paul DiFilippo, P. Eng.	Hydro One Networks, Inc.
Member	Mark Gutzmann, P.E.	Xcel Energy, Inc.
Member	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.
Member	John W. Miller	Georgia Transmission Corporation
Member	Steve Paglow	American Electric Power
Member	Rick Purdy, P.E.	Dominion Virginia Power
Member	Patrick Sorrells	Sacramento Municipal Utility District
NERC staff	Scott Barfield-McGinnis (Standards Developer)	North American Electric Reliability Corporation
NERC staff	Phil Tatro (Technical Advisor)	North American Electric Reliability Corporation