Meeting Notes
Project 2010-05.1 Protecting System Misoperations Standard Drafting Team

August 6-9, 2013

Excel Energy – Marquette Plaza, 13th Floor
Minneapolis, MN

Administrative

1. **Introductions**
   The meeting was brought to order by Mark Kuras, chair, at 8:20 a.m. CT, Tuesday, July 6, 2013. He thanked Mr. Gutzmann with Xcel Energy for hosting the meeting for the standard drafting team (SDT or team). Mr. Kuras noted NERC staff raised concerns during the quality review of the standard from the last in-person meeting (May 7-9, 2013) and conference call (May 28, 2013). Mr. Kuras' comments included a note about the two proposed alternative approaches from Mr. Barfield. Those in attendance were:

Name	Company	Member/ Observer	In-person (IP) or Call/Web (W)			
			8/6	8/7	8/8	8/9
Mark J. Kuras	PJM Interconnection, LLC	Chair	IP	IP	IP	IP
Paul DiFilippo	HydroOne Networks, Inc.	Member	W	W	W	W
Mark Gutzmann	Xcel Energy, Inc.	Member	IP	IP	IP	IP
Bill Middaugh	Tri-State G & T Association, Inc.	Member	W	W	W	W
John W. Miller	Georgia Transmission Corporation	Member	W	W	W	W
Steve Paglow	American Electric Power	Member	IP	IP	IP	IP
Richard A. Purdy, PE	Dominion Power	Member	W	W	W	W
Kenneth Hubona	Federal Energy Regulatory Commission	Observer	W	W	W	W
Scott Barfield-McGinnis (Standard Developer)	North American Electric Reliability Corporation	Observer	IP	IP	IP	IP
Steven Eldridge	North American Electric Reliability Corporation	Observer	IP	IP	IP	IP

Name	Company	Member/ Observer	In-person (IP) or Call/Web (W)			
			8/6	8/7	8/8	8/9
Michael Gildea (Reliability Standards Advisor)	North American Electric Reliability Corporation	Observer	-	W	-	-
Phil Tatro (Technical Advisor)	North American Electric Reliability Corporation	Observer	IP	IP	IP	IP
Gary Carlson	M Power Generation	Observer	W	-	-	-

2. **Determination of Quorum**
NERC standard drafting meetings require two-thirds of the members to meet quorum when a particular matter requires a vote. Quorum was achieved on all four days of the meeting as seven of the ten members were present.

3. **NERC Antitrust Compliance Guidelines and Public Announcement**
NERC Antitrust Compliance Guidelines and public disclaimer were reviewed by Mr. Barfield. There were no questions. Mr. Barfield also referred everyone to the two new NERC policies and demonstrated where to find them on the NERC website. The policies are related to use of the email listserv and standard drafting team meeting conduct. Each subsequent day of the meeting Mr. Rogers reminded in-person attendees and audio participants that the NERC Antitrust Compliance Guidelines, public disclaimer, and policies remain in effect.

4. **Review Roster**
Mr. Barfield noted that the roster posted on the NERC project page was not up-to-date because several members needed to be removed due to resignations. Mr. Art Buano resigned from the team due to his change in employers. Mr. Barfield reached out to members Mr. Martin Bauer and Mr. Tim Seeber. To date, Mr. Seeber acknowledged his responsibilities would not permit him to continue and Mr. Bauer had not responded to communications. Mr. Barfield took an action item to update and repost the roster.

5. **Review meeting agenda and objectives**
Mr. Barfield reviewed the meeting agenda and objectives.

Agenda

1. **Revise the standard**
Mr. Barfield presented an alternative approach (attached #1) to the team and explained its merits over the current working draft. The new approached placed emphasis on conducting an analysis of each Misoperation to be responsive to the posted SAR and which was also not addressed in the current working draft. The Alternative Approach 1 removed the proposed "action plan" requirements to address industry confusion on the differences between an "action plan" and the Glossary of Terms

Used in NERC Reliability Standards term "Corrective Action Plan" or CAP which were both found in the draft standard. The Alternative Approach 1 restructured the draft Requirement R1 to focus on analyzing each BES interrupting device operation which would result in creating tangible compliance evidence of "reviewing" such operations for Misoperations. This approach was responsive to feedback received from NERC Compliance staff; however, the drafting team noted that it placed an undue focus on those correct operations from a compliance standpoint. The team understood NERC Compliance's concern that for evidence, an entity might only have a simple list of operations with a column labeled "Was a Misoperation" where the entity would document a response of "yes" or "no," for example. The team concluded that requiring a substantive amount of evidence for the majority (i.e., +90 percent) of correct operations would direct valuable resources to compliance activities rather to reliability activities of investigating identified Misoperations for the cause(s). The Alternative Approach 1 also strengthened R1 by including both the owner of the BES interrupting device that experienced the operation and the other owner of the Protection System that might be notified to review its Protection System components for Misoperation or a cause of a Misoperation. This eliminated the "if then or do loops" of the current draft which was a source of confusion.

With Alternative Approach 1 proposing the removal of the "action plan" references (R2 and R3 – See Attachment 1), Requirement R2 (Alternative Approach 1) was simply replaced by a notification Requirement to ensure that the other owners would be notified. Since the creation of a CAP was alternatively proposed as a part of the new R1, Requirements R4 and R5 (Attachment 1) were reduced to a new R3 (Alternative Approach 1) to only implement any developed CAP. This approach received drafting team discussion. Mr. Barfield provided the following explanations. In Requirement R1, the 90 calendar days is intended to provide an incentive for an entity to complete its analysis, thus eliminating the need for notifications.

In Requirement R2, Mr. Barfield noted that the 90 days periodic time limit is started by the operation for the BES device owner or when another owner receives notification. In addition, he noted that the team should consider formally defining the term "Composite Protection System" specific to the standard or propose as a new term in the Glossary of Terms Used in NERC Reliability Standards. All of which could support the Misoperation definition and clarity in the standard.

The current draft definition of "Misoperation" is:

> "The failure of an Element's composite Protection System to operate as intended. The composite Protection System is all protection for a given Element, such as primary, secondary, backup, and communication-assisted relay systems, which function collectively to protect the Element. Protection Systems which provide remote backup protection are not included in an Element's composite Protection System."

The new definition of "Composite Protection System" which was pulled from the above "Misoperation" draft is as follows:

> "The total complement of the Protection System(s) that function collectively to protect a BES Element such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded."

The resulting change to the draft definition of "Misoperation" was:

> "The failure of an Element's Composite Protection System to operate as intended. Any of the following is a Misoperation:" (*Definition excludes this six categories for simplicity*)

The team agreed to formerly define for use in the Glossary of Terms Used in NERC Reliability Standards. The team discussed the use of "analysis" in the Requirement which is consistent with the intent of the Standards Authorization Request (SAR) and takes the place of the phrase "action plan" which was confusing to industry. The SDT concurred that it preferred "investigation actions" over "analysis."

The team also discussed Alternative Approach 2 (attached) and did expressed that the Alternative Approach 2 was preferred. In all, the team spent the first day of the meeting considering the alternative approaches by Mr. Barfield. There was no substantive discussion concerning the proposed Alternative Approach 3 (attached), Requirement R3. Mr. Kuras agreed that the SDT would consider this type of approach if the standard was not gaining industry support.

The result of the Alternative Approach 1 approach discussions was to continue with the current working draft and not implement any of the alternative approaches; however, some points were gleaned from the discussions and applied toward the current working draft. This conclusion was based on the expectation that the drafting team is being responsive to stakeholder comments and that presenting a wholesale change would not result in moving the standard forward.

The team's focus on revisions was primarily contained in Requirement R1. They discussed the modifications to Requirement R1, Parts 1.1 through 1.3 that provided additional clarity. More substantively, the team added Part 1.4 to provide a mechanism to facilitate entities with continuing their activities to determine a potential Misoperation.

Mr. DiFilippo questioned what the issues were from NERC Compliance and staff quality review. Specifically, issues concerning the team's current revisions in response to comments. Mr. Barfield noted that there were no formal documented quality review notes as the standard receives quality input from a number of sources. The most notable was Compliance's concern about the measurability of Requirement R1. The concern in Requirement R1 (Attachment 1) was the population of evidence. Previous comments and team meetings noted concern about having to retain evidence of every BES interrupting device operation. NERC Compliance communicated that based on the way the current working draft of Requirement R1, that an auditor would most like approach assessing compliance by first requesting the full set of operations. The SDT agreed that the intent is only to focus on the set of operations that were Misoperations, not those that were correct operations. The team did not have a viable solution to address the audit approach. Mr. Barfield asked the team if they believed that their revisions would result in an additional 20 percent in affirmative votes to obtain industry approval. Overall, the team felt the standard was headed in the right direction according to the response to comments; however, the Misoperation definition for Slow Trip needed additional review because comments reveal a lack of clarity.

The team decided to review the Slow Trip concerns about the clarity of how to identify a Slow Trip. Discussion included the ability for an entity to know critical clearing times. All agreed that would have an unintended consequence of requiring the entity to know all clearing times and an undue burden on the Transmission Planner.

The current draft of categories 3 and 4 are as follows with typical redlining to show what the team agreed upon:

3. **Slow Trip - During Fault –** A ~~c~~Composite Protection System operation that is slower than required for a Fault on the Element(s) it is designed to protect. Delayed clearing of a Fault is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or ~~if it caused a failure to coordinate with~~ resulted in the operation of any other Element's Composite Protection Systems.
4. **Slow Trip - Other Than Fault –** A ~~c~~Composite Protection System operation that is slower than required for a non-Fault condition, such as a power swing, under-voltage, over excitation, or loss of excitation, for which the Composite 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 ~~if it caused a failure to coordinate with~~ resulted in the operation of any other Element's Composite Protection Systems.

The team considered a revision to the Applicability Section 4.2, Facilities, concerning underfrequency load shedding (UFLS). The team reworded the UFLS provision to be as follows:

Original text: "Underfrequency Load Shedding (UFLS) that trips a BES Element."
Revised text: "Protection Systems that are used for underfrequency load-shedding that are intended to trip one or more BES Element."

The team agreed that the revision more clearly denotes the conditions and corrects capitalization usage of the term. Based upon guidance from Mr. Barfield, the team further removed the exclusionary references in Section 4.2, Facilities concerning Remedial Action Schemes (RAS) and Special Protection Systems (SPS) because the Applicability should be what is for inclusion, not exclusion.

The team made other revisions to the standard, but the most substantive rewrite occurred in Requirement R1 (See Attachment 1). Changes were made to the Violation Severity Levels (VSL) to comport with the work the team did in the Requirements. The team made a number of edits to the PRC-004-3, Application Guidelines. Most significant revisions included making comporting changes to the definitions, grammatical corrections, formatting, and citations.

A flowchart was developed by Mr. Miller; however, the team could not reach consensus on the flow of Requirement R1. The team decided to defer until the next meeting.

2. **Review consideration of comments**
   The team reviewed and modified some of the responses to comments based on changes made to the standard.
3. **Review of the schedule**
   Mr. Barfield reviewed the schedule to update the team on when certain activities may occur, such as, the posting and next meeting.
4. **Action items or assignments**
   - SDT – Conduct outreach on changes to standard.
   - Mr. Barfield – Update the SDT Roster, review Issues and Directives document, and Implementation Plan
   - Mr. Gutzmann – Mapping Document
   - Mr. Kuras – Review Consideration of Comments
   - Steve Paglow – Review the Guidelines and Technical Basis
5. **Next steps**
   - Complete assignments and update Mr. Barfield on expected completion
   - Post for a 45-day formal comment period in late August to finish in early October 2013
6. **Future meeting(s)**
   Tentative meeting the week October 28, 2013, location to be determined.
7. **Adjourn**
   The meeting adjourned at 12:21 a.m. CT on Thursday, August 9, 2013.

Attachment 1[1]

R1. For ~~each~~ BES interrupting device~~(s)~~ operations caused by a Protection System ~~operation~~ or by manual intervention in response to a Protection System ~~operation~~ failure to operate, each Transmission Owner, Generator Owner, and Distribution Provider shall: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]

1.1 If the entity owns the BES interrupting device(s) and all of the Protection System component(s), within 120 calendar days, ~~determine~~ identify whether or not any Misoperation occurred ~~if the Protection System operation was a Misoperation, including any identified cause~~.

1.2 If the entity owns the BES interrupting device(s) and does not own all of the Protection System component(s), within 120 calendar days:

- If its Protection System component(s) caused the Protection System operation~~, and if so,~~ identify whether or not a Misoperation occurred.
- ~~was the Protection System operation a Misoperation, including any identified cause.~~
- If its Protection System component(s) did not cause the Protection System operation, whether the cause is known or unknown, notify the ~~all~~ other owner(s) of the Protection System component(s).

1.3 If an entity receives notification, per Requirement R1, Part 1.2, ~~determine for its Protection System component(s) if the Protection System operation was a~~ within the greater of either 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, identify if its Protection System component(s) caused the Protection System operation and whether or not a Misoperation occurred ~~Misoperation, including any identified cause, within the latter of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation~~.

1.4 If a Misoperation has been identified, perform at least one investigative action to determine the cause, every two calendar quarters after the Misoperation was 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 determined.

~~R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the component of a Protection System that misoperated shall for each Misoperation without an identified cause, within 60 calendar days of the completion of Requirement R1, complete the development of an **action plan** that identifies investigative actions and/or Protection System modifications, including a work timetable. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-Term Planning]~~

[1] Attachment 1 was pulled from the SDT's working document. This information may change or may have changed.

~~R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each **action plan** and update, when actions or timetables change, until one of the following completes the action plan: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]~~

- ~~The cause of a Misoperation is determined, identify the cause.~~
- ~~If the cause of a Misoperation is not determined, make a declaration explaining why no further actions will be taken and/or no Protection System modifications will be made.~~

R2~~4~~. Each Transmission Owner, Generator Owner, and Distribution Provider that owns the component of a Protection System that Misoperated ~~misoperated~~ shall, within 60 calendar days of first identifying a 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) and ~~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 could reduce BES reliability and that no further corrective actions will be taken.

R3~~5~~. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each CAP, and update each CAP if actions or timetables change, until completed. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Long-Term Planning]

Alternative Approach 1[2]

R1. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall notify, within 90 calendar days, all the other owners of the Composite Protection System when either:

- The BES interrupting device operation was a Misoperation and was not caused by the owner's portion of the Composite Protection System;
- The BES interrupting device operation was a Misoperation and the cause was not determined; or
- The owner is unable to determine if the BES interrupting device operation was a Misoperation.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that experienced an operation or group of operations or receives notification from the BES interrupting device owner of the operation(s) shall analyze its portion of the Composite Protection System. The analysis shall occur within 90 calendar days of the operation or notification thereof, and any continuing analysis activities shall be documented at least every 90 days until one of the following completes the analysis:

- Determination that the Protection System operation was not a Misoperation; or
- Determination that the Protection System operation was a Misoperation, including:
    1. identification of the actual cause(s) of the Misoperation including the evaluation of other locations, or declaration that no cause was determined; and
    2. the <u>creation</u> of a Corrective Action Plan(s) or declaration of why corrective actions are beyond the entity's control or could reduce Reliable Operation and that no further corrective actions will be taken.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each Corrective Action Plan (CAP) and update each CAP when actions or timetables change, until completed.

[2] Attachment 1 was pulled from the SDT's working document. This information may change or may have changed.

Alternative Approach 2[3]

R1. Each Transmission Owner, Generation Owner, and Distribution Provider, for its portion of the Composite Protection System, shall perform actions, at least every 90 calendar days commencing from the BES interrupting device operation for the owner or notification by the owner thereof, until the entity is able to declare:

- Each Protection System operation that is not a Misoperation, or
- Each Protection System operation that is a Misoperation that included either:
  - A determination it did not cause the Misoperation;
  - Identifying a cause of the Misoperation including why no further action would be taken; or
  - The identification of the actual cause(s) of the Misoperation.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall notify, within 90 calendar days, all the other owners of the Composite Protection System when either the entity:

- Documented its portion of Composite Protection System operation as not a Misoperation.
- Identified its portion of the Composite Protection System as not the cause of the Misoperation; or
- Could not identify its portion of the Composite Protection System as the cause of the Misoperation.

R3. Each Transmission Owner, Generation Owner, and Distribution Provider upon determination of a cause(s) of the Misoperation for its portion of the Composite Protection System shall either:

- Create a Corrective Action Plan(s) including an evaluation of other locations within 90 calendar days of first identifying a cause; or
- Declare why corrective actions are beyond the entity's control or could reduce Reliable Operation and that no further corrective actions will be taken within 90 days of first identifying the cause.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each Corrective Action Plan (CAP) and update each CAP when actions or timetables change, until completed.

[3] Attachment 1 was pulled from the SDT's working document. This information may change or may have changed.

Alternative Approach 3[4]

R1. Each Transmission Owner, Generation Owner, and Distribution Provider, for its portion of the Composite Protection System, within a 90 calendar day periodicity, and commencing from the BES interrupting device operation for the owner or notification by the owner thereof, shall:

- Identify its Protection System operation as not a Misoperation, or
- Analyze its Protection System Misoperation, until one of the following completes the analysis:
  - A determination that the Protection System did not cause the Misoperation;
  - Documenting the reason(s) for no further analysis will be taken to determine the cause(s) of the Misoperation; or
  - The identification of a Misoperation cause.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall notify, within 90 calendar days, all the other owners of the Composite Protection System when one or more of the following are true:

- Identification that its portion of Composite Protection System operation is not a Misoperation;
- Analysis reveal it is not the cause of the Misoperation; or
- Analysis did not reveal a cause of the Misoperation.

R3. Each Transmission Owner, Generation Owner, and Distribution Provider upon determination of a cause(s) of the Misoperation for its portion of the Composite Protection System shall either:

- Create a Corrective Action Plan(s) including an evaluation of other locations within 90 calendar days of first identifying a cause; or
- Declare why corrective actions are beyond the entity's control or could reduce Reliable Operation and that no further corrective actions will be taken within 90 days of first identifying the cause.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement each Corrective Action Plan (CAP) and update each CAP when actions or timetables change, until completed.

[4] Attachment 1 was pulled from the SDT's working document. This information may change or may have changed.