

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)
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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 with the 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 identified 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 Ingebrigtsen

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 unfaulted 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.

<p>(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...".</p>
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

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Yes

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Yes

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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 "Unnecessary 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.