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Group
Dominion
Mike Garton
No
Dominion supports the stated purpose up to the comma. The qualifying language after the comma is ambiguous and not supported in the Requirements of this standard.
No
Yes
Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, which is would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The standard should be retired or mapped to another standard.
Individual
Michael Falvo
Independent Electricity System Operator
No
We agree with the first part of the purpose statement, but do not find it necessary to include the second part since "meeting the system performance specified within requirements established in

other approved NERC Reliability Standards" is universally true for all standards. No one single standard can assure reliability on its own; multiple standards must be complied with to meet one or more reliability objectives and performance targets. We suggest to remove the part "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards".

No

Yes

No

We do not agree or disagree with the 10% deviation threshold. In the Technical Justification document, the SDT indicates that "The SDT investigated various inputs that would trigger a review of the existing Protection System Studies, and determined through the experience of the SDT members, along with informal surveys of several regional protection and control committees, that variations in Fault currents of 10% or more are an appropriate indicator that an updated Protection System Study may be necessary." Lacking statistical or detailed studied results, this basis is as good as any. However, there does not appear to be any assessment made on the potential BES reliability risks when the Fault current deviates by less than 10%. Many Protection Systems' settings are linked to Fault current level and as such, deviation as low as a few percent may render a Protection relay not operating as intended. We suggest the STD to assess the risk of not conducting a verification study for the Protection Systems when Fault current deviates from past values at a lower range to either confirm that a 10% deviation would be a safe trigger, or revise it according to the findings of the risk assessment. (NTD: we may also suggest that a Protection System Study should be required for every BES modification that is in the electrical proximity of the Interconnected Facility and is expected to modify the Fault current levels.)

Yes

No

We agree with the need to provide an agreement to the study results and to confirm acceptability of the proposed changes (other than those conditions identified in Requirement 3, Part 3.3), but R4 is unclear in a number of aspects, as follows: 4.1 There is no requirement or provision for the receiving entities to express disagreement, with rationale, and R4 does not require resolving the differences. Both need to be added. 4.2 Based on the language in Part 4.1, we assume R4 applies to the receiving entities. Hence we interpret 4.2 to require the receiving entities to confirm with the sending (or the initiating) entities of their agreement with the proposed changes. In that vein, the wording in 4.1 "confirm the affected Interconnected Facility owners" is unclear as to who needs to confirm with whom. Suggest to reword 4.1 to: "Prior to the in-service date of any planned change at the Interconnected Facility, confirm with the Interconnected Facility owners that initiated the changes that agreement with the Protection System(s) changes as described in Requirement R3, Part 3.1. was reached." 4.3 requires that the receiving entities confirm with the initiating entities of the changes made under Part 3.3, for which prior agreements are not necessary or perhaps possible. However, there is no requirement or provision for the receiving entities to express a disagreement, with rationale, and suggest alternative setting changes, or resolve the differences. This needs to be provided.

Yes

Yes

We generally agree with the VRFs and the VSLs for the requirements as presented, but we have concerns with some of the requirements and hence reserve our comments until we see revisions made to these requirements.

1. As a general comment, we do not support defining new terms which have limited applications (e.g. for use in one or very few standard) and which are short and therefore can be equally effectively expressed in the requirement that the term or its intended meaning is used. Adding new terms to the NERC Glossary when not absolutely necessary creates unnecessary maintenance workload and dependency among standards that use the same term, making it far more difficult to revise a

standard without addressing the ripple effects. While we do not oppose to defining the term Interconnected Facilities as it serves to clarify and provide the boundary of the Facility, and we see its potential application to other standards, we disagree with defining the term "Protection System Study". The definition contains an objective "operate in the desired sequence for clearing Faults" that should be stipulated in the standard requirements themselves. Further, as suggested below, the requirements that this term is used can be easily revised to convey the meaning of the definition: R1, 1.1 Perform a study for each Interconnected Facility to verify that Protection Systems operate in the desired sequence for clearing Faults and remove from service only those Elements required to isolate Faults as follows: 1.1.1 Within 36 calendar months after the effective date of this standard, if no such study for that Interconnected Facility exists that was performed on or subsequent to June 18, 2007 R1, 1.2 Provide to each affected Interconnected Facility owner a summary of the results of each study performed pursuant to Part 1.1 of this requirement, (including, at a minimum, the Protection System(s) reviewed, any issues identified, and any revisions proposed) within 90 calendar days after the completion of each study. R2, 2.2 Calculate the percent deviation between the Fault current values (single line to ground and 3-phase for the bus(s) or Element(s) under consideration) used in the most recent study performed under Part 1.1 of R1 and the Fault current values... $V_{pss} = \text{Fault current value used in the most recent study}$ R4, 4.1 Within 90 calendar days after receipt, confirm agreement with the summary results of a study as described in Requirement R1, Part 1.2. Conforming changes can be made to the associated Measures and VSLs. 2. We do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. If this is a training requirement, it should be transferred to the appropriate PER standards. c. Measures M1 is removed from the standard. This does not conform with the Elements of a Reliability Standard template, specifically those specified in the "Mandatory and Enforceable Sections of a Standard". d. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. However, leaving this not measurable and unnecessary requirement in PRC-001-3 is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT could have proposed a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee's advice/direction for appropriate actions. 3. The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after "where such explicit approval is required" in the Effective Dates Section on P. 2, to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Individual

Thad Ness

American Electric Power

No

AEP recommends the removal of the language, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards". AEP recommends as an alternative to the removal of the language, modification of the language to reference the TOP standards that should be adhered to in conjunction with PRC-027.

No

No

36 months is not adequate for unique Protection System Studies to be conducted for the TO, GO, and DP. The interface and coordination requirements as written will require close communication with a vast number of interconnected facilities. In addition the generation landscape changes over the next few years with the large number of generation retirements and additions will continually change the short circuit model. AEP feels that these contributing factors will lead to time requirements above the proposed 36 months currently in the standard. AEP would require a minimum of 60 months to

complete this work as the AEP system exists today. An added complication that will impact this time requirement is the approval of FERC Order 1000, which could result in additional interfacing TO's inside AEP's footprint. In addition, NERC's rationale for R1 states that "the SDT has no evidence there is widespread miscoordination between Interconnected Facilities that warrants a shorter time frame." If this is the case, then there should be no issue with extending this timeframe. Using the word "demonstrates" within the definition for Protection System Study could be interpreted as requiring an actual, operational test rather than a simulation study. We recommend changing the definition to "a study that demonstrates that the existing or proposed Protection System design will enables the Protection System to operate in the desired sequence for clearing Faults." Is using the defined term "Protection System" appropriate? Does it possible bring things into scope (CTs, PTs, Station batteries) which should not?

Yes

Yes

No

The 90 Day window will not be sufficient during the initial R1 time frame. AEP suggests 180 days during the R1 compliance window.

No

AEP has suggested adjusting the time requirements, as stated in Question 3 and 7. These time requirements should be included and the VSLs should be scaled accordingly.

We agree with the comment in the background section that the SAR written for this project was focused on System Protection Coordination, and we recommend that PRC-001 R1 should be moved to another standard more focused on operations or training. TOP-006 R3 might be a more appropriate standard for such a requirement. For R1, the standard needs to clearly state the boundaries of the required study(ies). In addition, detail is needed regarding the depth of study away from the point of interconnection, and how far into the generating unit auxiliary system or interconnecting system must be evaluated. Based on the redline provided where R3 and R4 have been removed, and assuming the SDT is not willing to moving the sole remaining requirement to another standard, the title and purpose of resulting PRC-001 would need to be changed. If PRC-001 R1 remains as it is, the phrase "familiar with the purpose and limitations of protection system schemes" needs additional clarity. Doing so might help prevent a CAN from being developed to provide such clarity. AEP suggests the time requirement on R4.3 associated with R3 needs to be extended to 60 days.

Individual

Joe Tarantino

Sacramento Municipal Utility District

Yes

We agree with the purpose of the standard. We disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT really believe that this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We feels this is regulatory overkill and not indicative of a results based standard.

No

No

There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.

No

We do not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.

Yes

We agree with the list in R3.1. We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state – replacing a failed relay like for like.

Yes

We agree that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.

No

No, we do not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity feels it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.

We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I.

Group

Southwest Power Pool NERC Reliability Standards Development Team

Jonathan Hayes

No

We would ask that the team revise the second part of the purpose to lead in with "In accordance with the system performance specified within requirements established in other approved NERC Reliability Standards" If left as is it reads like you are required to do both the first and second parts of the purpose. This proposed language requires the initial goal of this standard and references that it will do so under the system performance specified in NERC standards.

No

Yes

Yes

No

In R3 we would suggest that re-rating could be use as a temporary procedure which is addressed in the TOP standards and if the drafting team needs to include these types of re-ratings that they be more specific to exclude the temporary re-ratings. Changes to generator unit(s), including replacements, Output change that causes a change in the protection system, and impedances

No

We agree with the need but feel it needs to be more detailed to include wording that would address

that the coordinated owner has all appropriate data to perform the study before his 30 day timeline begins. We would also like to see a conflict resolution process included under this requirement.

Yes

Yes

In R2 the 24 month time period needs to be changed to 60 months. If fault currents are already being calculated for changes to the system there should be little to no need for a more current check of the fault currents. We feel like the 24 months could be burdensome to smaller entities. We would ask that PRC001-3 be retired and the requirement in it to be moved to a SAR for an existing PER training standard. It also seems incomplete that a standard with a single requirement has no measures. Is there a need for the defined term "Protection System Study" in this standard to also be a new term in the NERC glossary of terms? Is there other wording that could be used in place of this new term since it is only being used as part of this standard?

Group

National Grid USA / Niagara Mohawk

Michael Jones

Yes

No

Yes

As a TO our experience has been that many GOs do not reply to requests for information. If the 36 month window cannot be met by a TO because information requests are ignored what recourse does the TO have to avoid a penalty for non-compliance?

Yes

Please clarify where the fault is to be placed and where the deviation is to be observed. One possibility is to place the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to said bus.

Yes

Yes

Yes

In the event that someone hands you a study of their entire system or of all their interconnections you should only be responsible for reviewing study results for those interconnections in which you are a participant. Furthermore, what if you don't agree with the study results you've been handed? The text as written literally commands you to agree with them! The text should be reworded to require a response (not necessarily agreement) within 90 days and relative only to the portion of the study applicable to interconnections you participate in.

Yes

1.Regarding the definition of "Interconnected Facilities," when the functional and operating entities are part of the same corporate entity documented correspondence within that same corporate entity seems of little benefit. In fact, it could be the same individual wearing two hats in the same corporate entity who would have to document communications with him/herself. 2. Example process on page 22 should not automatically make it the responsibility of entity B to propose a solution to a problem discovered by entity A quite possibly resulting from system modifications initiated by entity A. Whether entity A or entity B is in a better position to propose a solution depends entirely on the circumstance and there needs to be flexibility as to who is obliged to come up with a fix. 3. Application Guidelines, Fig. 2 and Fig. 5 require the TO to verify "...the generator Protection Systems..." coordinate with the TO's systems. The scope of generator protection systems should be narrowed to just distance relays and overcurrent relays that look out onto the TO's system. If the

high side winding of the transformer that interconnects to the TO is ungrounded and zero sequence overvoltage protection is provided for the transmission, then that would be appropriate to include in the scope of TO responsibilities too. The expertise in other types of generator protection likely resides with the GO and not the TO so it would be best if the GO handled the coordination of those other types of protection. 4. Application Guidelines, Fig. 3 requires the TO to verify the DP's and the GO's protection systems coordinate with the TO's. Yet the GO doesn't even connect directly to the TO. It should be the DO that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer (assuming the DP has installed transmission protection at the sub) and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. Furthermore it would require that the DP keep the TO continuously apprised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination of what could be a multitude of interconnections to the DP. Furthermore, the scope of the text "...generator protection systems...." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't even own, maintain or set. When study work is required to interconnect a GO to an entity, the entity is commonly reimbursed by the GO for study work. Yet this app guide requires a TO to perform study work for the benefit of a GO which does not even directly interconnect with it so how will the TO be reimbursed for it's efforts?

Group

Pepco Holdings Inc. & Affiliates

David Thorne

No

1)The language in the Statement of Purpose needs to be reworded. The phrase "remove from service only those elements required to isolate faults" may restrict certain protection practices in widespread use today, where coordination on tapped distribution facilities is achieved via auto-reclosing rather than via coordinated time delays. For example, a BES line (protected by a high speed DCB or POTT pilot scheme) is tapped by a distribution provider as demonstrated in Figure 3 of the Application Guidelines. Very often for distribution taps like these, rather than requiring the distribution provider to establish a costly transmission class pilot scheme terminal at breaker C with communication links to A & B, it is common to let the pilot scheme reach into (but not thru) the transformer at C. For faults in the transformer the high speed transformer relays will operate to trip and lockout breaker C. However, the pilot scheme at A & B will also trip simultaneously. Breaker C will lockout and A & B will auto-reclose to restore the line. Coordination is achieved via auto-reclosing. For faults on the line, A & B will trip via the pilot scheme, and if generation happens to be running either C will trip, or the generator will trip depending on scheme design. Reclosing at A & B would be delayed and / or voltage supervised to ensure generation has been removed prior to auto-reclosing. In the above scenarios since the line tripped for a fault in the transformer, or the generator tripped for a fault on the line, it would violate the requirement to "remove from service only those elements required to isolate faults". The language used in the proposed definition of Protection System Study is slightly better, using the phrase "demonstrates ... Protection Systems operate in the desired sequence for clearing faults". The problem here is who determines what is the "desired sequence"? Would a scheme, which is purposely designed as described above and acknowledged by the Transmission Planner and Transmission Operator, be considered to operate in the "desired sequence" for clearing faults? 2)The language in the standard needs to be re-visited to enable these types of protection interfaces with distribution providers having limited generation resources connected downstream. Also, if system reliability was truly an issue for this example, the interconnection should not have been a simple tap on the line, but rather a ring bus should have been established at the interconnection point.

No

No

Each owner should already possess information demonstrating that their protective devices are set to "coordinate" with adjacent protection systems. However, the documentation that presently exists may not be in the form of a formal "coordination study" in a format suitable for audit purposes. Some

guidance should be provided indicating what form of documentation is expected, especially by the TO. For instance, on transmission tie lines between different TO's coordination of zone distance elements is fairly straightforward and can be accomplished without a traditional "coordination study". Also settings on pilot schemes need to be exchanged in order to allow for proper operation, but this is also not what is considered a traditional "coordination study". On the other hand, coordination between GO's and TO's is even more complicated. Without some direction as to what specific documentation is required it is difficult to estimate how many existing interconnection points would have to be re-visited in order to produce the required auditable documentation. Some specific examples of what specific type of documentation is required would be helpful. To be safe, most likely all interconnection points would be revisited to ensure adequate compliance documentation. Also, for each revised Protection Study produced (per R1.1) a formal review (R1.2) and approval (R4.1) would be required. As such, with the large number of interconnection points on the system a 60 month time frame would be more appropriate. The SDT acknowledged that they had no evidence that there is widespread miscoordination between Interconnected Facilities when establishing the arbitrary 36 month requirement.

No

The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2: R2.1 – Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. R2.2 – Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..." The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two entities), fault current in each "element under consideration" used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a "batch" screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 "Additions, removals, or replacements of transmission Elements".

No

The 10% threshold would be acceptable providing the following changes were made to Requirements R2.1 and R2.2: R2.1 – Re-word Requirement R2.1 to read: "Perform a short circuit study to determine the present maximum available fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities, not less than once every 24 months. R2.2 – Re-word Requirement R2.2 to read: "Calculate the percent deviation between the maximum available Fault current values (single line to ground and 3-phase) at the point of interconnection for the Interconnected Facilities used in the most recent Protection System Study and the Fault current values determined pursuant to Requirement R2, Part 2.1, using the following equation..." The existing wording requires one to "calculate the percent deviation between the fault current values ... for the bus(s) or Elements(s) under consideration". Including the phrase "or Element(s) under consideration" increases the complexity of the periodic fault screening requirement significantly. Instead of performing a relatively easy bus fault summary routine (available in most batch short circuit programs) individual branch current in various coordination pairs must be examined. Take for example the system shown in Figure 1 in the Application Guidelines. Instead of just screening the available bus fault current at the point of interconnection (the ownership boundary between the two

entities), fault current in each “element under consideration” used in the Protection study must be calculated. This would mean determining fault current flows through breakers A, B, C, D, E, F, G, & H) under various fault scenarios and comparing them to those used in the previous coordination study. This is far from a simple task and not conducive to a “batch” screening tool. The intended purpose of R2.2 is to catch external system changes that have over time led to gradual increases in fault current that may require the Protection System Study to be re-examined. A simple year to year bus fault comparison would serve this purpose. System changes at, or immediately adjacent to, the interconnection point, which could lead to a re-distribution of fault currents through the effected element(s), would be caught elsewhere under R3.1 “Additions, removals, or replacements of transmission Elements”.

No

1) Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? 2) Requirement R4.3 requires confirmation of agreement within 30 days of being notified of corrections made due to as found setting errors or emergency replacements of Protection System components. Again, what if the changes are not acceptable to the other party? Which entity is found not compliant, the one who proactively made the changes or the one who won't confirm agreement? This is the problem with mandating that an agreement between two parties be reached. It is further compounded by requiring that an agreement be reached within a set timeframe. 3) It is important to ensure that information on new, or modified, Protection Systems are shared between parties, so that each party may assess the impact of the change and ensure their Protection Systems are properly set and coordinated. The emphasis should be on sharing of information (such as relay setting changes) and not the details of performing the “Protection System Study” and all the associated approval schedules. As such, it may be reasonable to have a Reliability Standard to ensure setting information has been exchanged (which was the original intent of the PRC-001-1 standard). But it should be left at that. Mandating mutual agreement with compliance implications, without providing some outlet for a dispute resolution process seems unfair to either party. As such, we suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined above.

No

We suggest Requirement R4 be removed entirely or extensively re-written to address the concerns outlined in our response to Question 6.

No Comments

1) The SDT states that “the requirements in the proposed Reliability Standard PRC-027-1 take into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays”. However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. 2) The mention of “the appropriate use of time delays in relays” in the 2003 Blackout Report was in the context of the actuating time of relays in response to system overload

conditions, and generator protection to voltage and frequency excursions during stressed system conditions. The concern was that relays operated on overload before system operators could react and that some generators tripped (exacerbating the collapse) before other system schemes (UFLS or UVLS) could operate. 3)The solution was not to increase the time delay on Zone 3 relays (which would have been intolerable for fault clearing purposes) but to address the relay loadability issue in PRC-023, to make them immune from operating under heavy load conditions. Similarly the premature tripping of generators on voltage and frequency protection during stressed system conditions (not fault conditions) and coordination with system UFLS and UVLS schemes was discussed in the report. Likewise those issues have now been addressed, or are being addressed, in PRC-006, PRC-010, PRC-022, PRC-019, and PRC-024. 4)Similarly in the recent Southwest Blackout of 2011 the operation of relay schemes during overload conditions was a contributing factor. There was again no evidence of miscoordination of relay schemes during fault conditions. The unexpected operation of relays and SPS's during overload conditions could have been avoided by proper application of existing standards PRC-023 and PRC-014-0. 4)Based on the above, where is the historical evidence that the cause of major disturbances or cascading outages were the direct result of protective relay systems that were not properly coordinated during fault conditions? Reliability Standards should be adopted based on a need to address a known, or probable, reliability issue. As such, although we support the overall desire to ensure that protective systems are "properly coordinated"; we see little value in developing a new Reliability Standard to address something that is routinely practiced and which has not been demonstrated to be a contributor to major system disturbances, or cascading outages. Even the SDT in their rationale for Requirement R1.1 stated that they have no evidence that there is widespread miscoordination between Interconnected Facilities. In lieu of a formal standard to address relay coordination during faults, a simple technical reference document on Protective System Coordination issues may provide equal benefit to the industry. 5)PRC-001 With the vast majority of the requirements from PRC-001-1 being removed, the Title and Purpose of proposed standard PRC-001-3 no longer seem appropriate for the content remaining therein and should be revised. The only remaining requirement in PRC-001-3 states that "Each Transmission Owner, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. This does not seem to be a Protection System Coordination issue. 7) The definition of Interconnected Facilities should reference Registered Entities rather than functional, operating, or corporate entities. BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities Registered Entities (TOs, GOs, and/or DPs). 8) Is Facility and/or Element the best term(s) to use in the definition? It seems to say Elements that are joined by Elements? If not, should the definition be further revised. NERC Glossary of terms for Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components. NERC Glossary of terms for Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.) 9) Does joint own lines and stations create issues? Should the definition or standard make a distinction between principal owner and financial owners?

Individual

Russ Schneider

Flathead Electric Cooperative, Inc.

Yes

No

Yes

This seems like an adequate time, but it is unclear that smaller transmission dependent utilities really need to do this to maintain reliability and if their ratepayers would see any reliability benefit.

Yes

No

Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and

GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward
Yes
Yes
No
Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.
Group
Hydro One
Sasa Maljukan
No
The goal of this standard is to address co-ordination of protection systems between neighbouring entities. To achieve this goal, the efforts should focus on the co-ordination of protections between entities as outlined and described in the NERC SPCS paper "Power Plant and Transmission System Protection Co-ordination – Technical Reference Document (TRD)," dated July 2010. This standard should include the review/study of all protections requiring coordination not the ones dealing with faults only as identified in the above TRD. There should be one comprehensive study/report not spread out into 7-8 standards. If so, there are still protection elements that require coordination that have not been addressed such as: open-phase, loss-of-field, over-excitation, out-of-step, and negative sequence normal unbalance, etc. We don't see how a standard for Protection system co-ordination can rely on other standards to achieve the goal of co-ordinating protections for both Faults and other conditions that challenge co-ordination. The Purpose should be: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service only those Elements required to isolate from abnormal system conditions, while meeting the system performance specified within requirements established in NERC TPL Reliability Standards." If the above suggestions are not taken into consideration and the SDT decides to keep the requirements in the current form, the statement "...while meeting the system performance specified within requirements established in other approved NERC Reliability Standards." should be changed to include exact reference to standards or at least group of standards the SDT is referring to.
Yes
This is related to our comments from Question 1. We believe that the Planning Coordinators (PC) shall be included. PCs are accountable to conduct studies to determine critical clearing times, stable and unstable power swings, etc., to determine coordination. Transmission and Generator Owners do not have access to such information or the tools/experience to conduct such studies. In addition to this there is a possibility that the entity in charge of day-to-day operation of the Interconnection Facilities (likely registered as TOP only) doesn't own the facility and consequently is not registered as a TO. In this case, such facility or the facilities would be out of scope of this standard. We believe that the SDT should refine the Applicability section to encompass the above mentioned cases. From a reliability point of view, we think that this standard should not be applicable to Distribution Providers because the TO is mostly responsible of coordination of the protection with the DP.
No
Hydro One would like to suggest that 60 months would be a more realistic span of time needed in order to formally complete a documented study, or derive a time frame based on the number of interconnections that an entity must conduct studies for. Whether the systems are co-ordinated or not, the work needs to be carried out and documented. In the case of Hydro One there are almost 300 individual generator connections that belong to other entities many of whom do not have onsite protection experts. Most of these connections do not have a formal documented protection co-ordination study. Statements in R1.1.2 and 1.1.3: "unless the entity can demonstrate such a study is not required." and its corresponding measure: " or documentation demonstrating why a study is not required for changes described in Parts 1.1.2 and 1.1.3" are vague and don't give much guidance on

what would be the appropriate evidence in this case. Suggest adding examples of documents that can be used to demonstrate compliance.

No

Hydro One agrees with the need of a defined fault current threshold. However, we'd like to suggest a 20% threshold instead as most protection settings, if coordinated properly, must coordinate with system normal and under credible minimum system conditions, therefore, it is our opinion that a 10 % change should generally not affect coordination.

No

While we agree with the principle of exchanging information, R3.1 is confusing "...or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." We believe that this statement is too inclusive. It implies that changes in facilities other than the Interconnected Facility need to be communicated and is too open for interpretation. Suggest the scope be better defined and limited only to changes at the Interconnected Facility.

Yes

Yes

Yes

1. This standard has been written on the basis that one of the Entities initiates the process and that both, assuming 2 only, conduct their own independent Protection System Studies; and then at the end of the process they agree, etc. Based on our experience, it is more efficient that both parties work in cooperation to conduct the Protection System Study and that they produce one report document which is then approved by both entities as meeting adequate coordination requirements. The Protection System Studies report shall be dated, and include the fault values at the time of assessment and should be filed as compliance evidence. 2. The SDT states "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities...." This is contrary to the NERC TRD that indicated that there was plenty of co-ordination issues during the 2003 Blackout. Suggest removing this statement as it is contradictory and serves no purpose since the documented Protection System study has to take place regardless. 3. We feel the standard would be more useful to the industry if a list of applicable Protection System elements that require co-ordination is presented in the requirements section in line with the NERC white paper. Much like PRC-023 that identifies specific elements and corresponding numbers, we feel this approach would result in proper Protection System studies being undertaken for elements that are affected by this standard. The SDT claims some elements will be covered in other standards so the scope of elements that need co-ordination needs some clarity. 4. PRC-001-3 lists "first day of the first calendar quarter twelve months following" as the Effective Date. However, the implementation plan states that the effective date is the same as for PRC-027-1 which is "first day of the first calendar quarter that is three months beyond". Please clarify and ensure consistency. 5. Hydro One is questioning the purpose and existence of PRC-001-3 in its current form. It contains only one requirement that is very vague and not measurable. Suggest that the SDT retire that standard as a part of this project 6. To avoid confusion we ask the SDT to establish 1 to 1 correspondence between the requirements and measure. For example R2 measures should be M2 or M2.1, M2.2 rather than M3 and M4.

Individual

Anthony Jablonski

ReliabilityFirst

No

It may be appropriate to trigger a coordination review based on multiple criteria. For instance, perhaps coordination should be verified at the interconnection at least once every 7 years, as well as whenever the available fault current at the point of interconnection changes by more than 10%. There

may be other better indicators when coordination should be checked as well such as a percentage change in system impedances at the interconnecting buses. RFC also questions whether there is a justification for choosing the 10% criteria (rather than say 5%)

No

ReliabilityFirst believes the VRF for Requirement R4 should be High since it requires completion of the coordination activities. Lack of coordination of Protection Systems can result in larger scale outages.

ReliabilityFirst offers the following comments for consideration: 1. Requirements R1, R2 and R4 a. Requirements R1, R2 and R4 do not follow the format of a typical Results Based Standard requirement (i.e. the parent requirement simply states "the entity shall:"). Result Based Standard risk based requirements should be in the following format: "who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome." ReliabilityFirst recommends modifying these three standards to conform to the Results Based Standard format. 2. Requirement R2 a. ReliabilityFirst questions why Transmission Owners only need to perform a short circuit study on Interconnected Facilities and not their internal system Facilities as well (Requirement R2). ReliabilityFirst believes it would be beneficial for Transmission owners to be required to determine present fault current values (and calculate the percent deviation between the Fault current values) for all internal system Facilities. 3. Need for PRC-001-1 Requirement R1 a. ReliabilityFirst believes PRC-001-1 Requirement R1 is ambiguous and believes the intent is covered in the NERC PER-003-1 standard. It will be very hard for an applicable entity to show that they are "familiar" with the purpose and limitations of protection system schemes applied in its area. Since ReliabilityFirst believes R1 does not enhance reliability, ReliabilityFirst recommends retiring PRC-001-1 Requirement R1 consistent with the effective date of the NERC PER-003-1 standard (effective date of 10/01/2012).

Individual

Martin Kaufman

ExxonMobil Research & Engineering

No

No

No

No

No

No

No

No

PRC-001-3 has a single requirement with no associated measure. Any standard requirement whose implementation can address a reliability gap in the Bulk Electric System should possess a quality that can be measured. The SDT should modify PRC-001-3 and provide a measure for Requirement R1 or redact the standard in its entirety.

Group

Luminant

Brenda Hampton

Yes

No
Yes
Yes
No
Luminant agrees with R3.1 and 3.2. Luminant suggests that the language in this requirement be revised so it is clear what is to be provided between the parties.
No
Luminant agrees with the need to reach an agreement on relay coordination based on the specific circumstances in R3.3.1 and R3.3.2. However, the time period to reach agreement of 30 days should be replaced with an agreed upon time schedule by all parties.
No
Luminant recommends that the time frame should be "according to an agreed-upon documented schedule between Transmission Owner, Generation Owner, or Distribution Provider. Luminant would recommend the removal of the 90 day requirement. 90 days may not fit all circumstances. It should be left between the parties to determine the timeline of the project and reaching agreement. This is what should be documented to ensure coordination of activities between the affected parties.
No
Based on the comments on Q6, the VSL would need to be modified. Q7 and 9, the VSLs would change accordingly to accommodate an agreed-upon time frame for acceptable relay coordination and a method for resolving issues surrounding obtaining an acceptable coordination where differences occur.
Comment on Requirement R1.2. The time frame listed may not be adequate under all circumstances or situations. Luminant recommends that the language be changed in this requirement as follows: "... Protection System Study performed pursuant to this requirement (including at a minimum, the Protection System(s) reviewed, any issued identified, and any revisions proposed) shall be in accordance to an agreed-upon schedule with a Transmission Owner, Generation Owner, of Distribution Provider." The corresponding measures will also need to be modified if this language is accepted.
Group
Progress Energy
Jim Eckelkamp
Yes
Yes
Yes
Yes
Progress Energy request re-evaluation of time for performing Short circuit study in R 2.1. Request 36 months which is same time frame in R1.
Individual
Jonathan Meyer

Idaho Power Company
Yes
Yes
Yes, Transmission Operators may own protection systems but not the interconnected element due to cost sharing agreements among Entities, for example. The applicability should be expanded to cover the Entity responsible for operation of the protection system element and interconnection.
No
No, Should a Protection System Study under R1 result in triggering of the other Requirements in the Standard, more time may be needed. An Entity could easily find themselves responding to multiple inquiries from Interconnectors while performing their own Studies. Additional time should be allowed to address the results of the Protection System Studies triggered during this implementation timeframe.
No
No, We are unsure whether a 10% trigger level is appropriate in this context as the location of the fault is not specified in this Requirement. Faults used to properly set a protective relay will be made at multiple locations and with various source conditions. The Requirement should be more specific in order to achieve consistent coordination among entities.
Yes
Yes
Yes
Yes, There appears to be no mechanism in the Requirement addressing if coordination changes are not acceptable. This should be addressed as 90 days could easily be exceeded in this scenario.
Yes
During our review it appears that an Entity will need to maintain an exceedingly large list of contacts for all Interconnected Facilities in order to ensure that the appropriate personnel receive and respond appropriately to Protection System coordination requests as Required by this Standard. With the probability of regular turnover occurring (retirements, transfers, etc.) at Interconnected Facilities, it would be helpful for a master list of Interconnected Facility Contacts for Protection Systems be held by a centralized Entity, such as a Reliability Coordinator, in order for an Entity to meet the timeframes specified and facilitate reliability via compliance with this Standard. This Standard will enforce consistent communication between Entities which is necessary for coordination of Protection Systems. It does not however, guide an Entity to set relays that will ensure proper coordination. Having a separate Entity verify coordination is desirable, but differences in experience, expertise, and analysis tools between Entities will not ensure proper coordination if methods of checking are not also part of the Requirements.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
No
The SDT proposed Purpose is confusing. IID proposes the following Purpose language: "To coordinate Protection Systems for Interconnected Facilities, such that during faults, those Protection Systems remove from service only those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards."
No
Yes
Yes

Yes
Yes
No
120 calendar days are suggested instead of 90 because verification of Protection System Study needs to be performed before an agreement can be made and it is time consuming.
Yes
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
No
Yes
Yes
Yes
No
Austin Energy (AE) agrees with the need to coordinate Protection System changes; however, AE believes R4.2 is not sufficiently clear. As written, one could interpret it to mean that a Facility owner must obtain consent on the changes listed under R3.1, not just the Protection System changes (such as relay settings). AE does not believe it appropriate to require a Facility owner to gain consent on the actual change to the Facility itself (such as changes to line lengths/conductor size or replacement of transmission system Element(s), generator units or generator step-up transformer). The Guidelines and Technical Basis (p 20 of PRC-027-1 Draft #1) states, "The purpose of this requirement is to assure the effects that planned changes have on Protection Systems at Interconnected Facilities have been considered by all affected entities." AE agrees with this concept and believes the SDT sufficiently covers it through R1.1.3 and R4.1. AE recommends striking R4.2 from the Standard.
No
Austin Energy (AE) believes that 90 days is sufficient for responding to summary results of a Protection System Study, but it is not always sufficient for completing the iterative discussions that often take place to resolve questions and potential concerns. The Guidelines and Technical Basis (p19 of PRC-027-1 Draft #1) states, "R4, Part 4.1 directs applicable entities, within 90 calendar days after receipt, to confirm agreement with the summary results of a Protection System Study ...; or absent such agreement, propose revisions to achieve acceptable results." AE asks the SDT to include this "absent such agreement" concept in R4.1 and extend the timeline to accommodate such revisions to one that is mutually agreed upon by the impacted parties.
Yes
Austin Energy (AE) agrees with PRC-027-1 in concept and is prepared to change our vote to affirmative once the SDT addresses the items in these comments. In addition to those provided as part of the specific questions, AE provides the following comments for consideration: (1) AE requests the SDT to identify a timeframe for R1.1.3. The Guidelines and Technical Basis (p17 of PRC-027-1 Draft #1) states, "The SDT believes that specifying a single time frame for evaluation of the wide variety of conditions that may be associated with a particular change is not appropriate ..." The

flowchart on page 21 shows a system change that triggers the need for a new study leading to a box that requires the study be performed within six months. Please remove the conflicting information. (2) AE supports a timeframe that requires a Protection System Study in accordance with a mutually agreed-upon schedule that includes confirmation of agreement with summary results (per R4.1) prior to the in-service date of any planned change. AE suggests the SDT identify this timeframe in R1.1.3 and delete R4.2. (3) AE requests that the SDT change the values in the % Deviation formula (R2.2) from VSCS and VPSS to ISCS and IPSS since V is typically used for voltage. AE also requests the SDT change the variable definitions from "fault current value ..." to "fault current magnitude ..." to clarify that the phase angle is not included.

Group

Bonneville Power Administration

Chris Higgins

No

The purpose of PRC-001-1 was "To ensure system protection is coordinated among operating entities." With the rewrite of PRC-001 to PRC-027, the standard drafting team has expanded the purpose to specify that only elements required to isolate faults are removed from service and that system performance established in other NERC standards is met. The two additions to the purpose of PRC-027 should be removed for the reasons described below. The statement in the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", only serves to unnecessarily complicate the purpose statement. BPA recognizes that the NERC standard does not void the requirements of other NERC standards, therefore, there is no need to state in the purpose that other NERC standards must be met. The statement in the purpose, "such that those Protection Systems remove from service only those Elements required to isolate faults", drastically expands the scope of PRC-027 over PRC-001. With this new purpose, BPA believes this puts NERC in the position of micromanaging how protection systems are applied. Although most protection schemes are intended to remove only the faulted element, it is not necessarily a problem if additional elements are removed, and there might even be reasons to remove additional elements. In some cases it might be significantly less expensive to design a scheme that allows the removal of additional elements. Protection engineers need to have the flexibility to apply protection schemes that meet the requirements of the project at hand. Creating standards with absolute requirements on how protection schemes are applied and set will eliminate the flexibility necessary to implement effective and efficient protection schemes. The Standard Drafting Team (SDT) does not have the ability to foresee all possible protection scenarios, and to create a standard whose purpose is to remove from service only those elements required to isolate faults will create unnecessary expense and difficulty. BPA strongly recommends that the statement "such that those Protection Systems remove from service only those Elements required to isolate faults" be removed from the purpose and that the standard be modified to eliminate this requirement.

No

No

This question assumes that the requirement to perform a protection system study is acceptable, and the question focuses only on the timeframe allowed. In BPA's opinion, the requirement to have a protection system study is objectionable and cause for disapproval of the standard. Therefore, the timeframe is irrelevant. In addition, the standard fails to make clear just what a protection system study is, either in the definition, the requirements, or the guidelines that follow. BPA believes that R1 is ambiguous and unacceptable.

No

This question assumes that the requirement to perform a mandatory short-circuit study every 24 months is acceptable, and the question focuses only on the percent change of the study results that will require notification. BPA believes that a short-circuit study should not be required and the percent change that triggers notification is irrelevant.

No

BPA believes that it is not practical to list all of the possible changes that could impact the coordination of protection systems. Any such list will likely lead to unnecessary notification in most cases, while failing to recognize unusual situations that could cause miscoordination. BPA is in favor of

a simplified approach where notification is provided to the owner of the remote terminal(s) whenever a change is made to the protection scheme at one terminal.

No

In many cases, one party of the interconnection is simply implementing the protection system changes provided by the other entity. Requiring the agreement of this party implies that the entity understands what is going on and is not a practical use of time and resources.

No

BPA believes that requiring an agreement from all parties could prevent the implementation of emergency changes.

No

BPA believes that in general, the VRFs and VSL's are too high.

Interconnections are no more prone to misoperations than other power system elements. A logical conclusion is that if the requirements of this standard are put in place for interconnected facilities, they should be put in place for all power system elements. The industry is quickly approaching a prescriptive environment in the protective relaying field which attempts to replace experience and judgment with a massive set of rules. These rules will never be able to eliminate miscoordination and misoperations, and the more rules we have, the more time and resources are diverted from dealing with the critical issues that arise. Entities are no longer free to use experience and judgment to decide what work is most important and instead, focus time and energy on the relentless schedule of NERC requirements. The purpose of the original System Protection Coordination Standard, PRC-001, was to ensure that protection systems were coordinated among entities. This should require only a simple exchange of data between entities when new facilities are added or changes are made. BPA implores the SDT to reduce the burden of the proposed standard by simplifying it and returning to the basic original purpose.

Individual

Don Jones

Texas Reliability Entity

No

We support this reliability objective, but feel that it may fall short of fulfilling all of the required Protection System coordination needs, resulting in a gap in the Standards. The major issue that we see in Protection System coordination is with coordination studies conducted WITHIN an individual entity, not between two or more entities. Using the Misoperation data as an indication, for CY2011, out of 202 total Misoperations in the ERCOT region, 46% were due to "Incorrect settings/logic design", however, less than 2% of the Misoperations occurred on Interconnected Facilities between different entities. This suggests the main problem with Protection System coordination is internal to an entity, not between two different entities. This Standard, as well as PRC-001, are somewhat silent as to what internal coordination should be considered "Good Utility Practice", even though there have been instances where internal coordination was not done.

No

Yes

Yes

Using a +/- 10% change is a good threshold, with the understanding that if a change in fault current value of less than 10% results in a need to change relay settings, then Requirement R3.1 will cover the coordination between entities in that case. Additional comment: For R2.1, Does the SDT also want to consider other system studies in addition to short circuit studies (e.g. critical clearing time studies at generation facilities needed for breaker failure coordination, equipment rating studies, or stability studies)?

Yes

Yes

Yes
Yes
In the Severe VSL for R4.3, the word "entity" was left out after "The responsible . . ."
Requirement R1.1.3: While we agree with the SDT rationale that R3 notifications may occur weeks or years prior to the change, we feel that a time frame should be included in this requirement rather than leaving it open-ended. We suggest that the Protection System Study be completed at least 60 calendar days prior to the in-service date for R3.1 and within 30 days after receiving notification for R3.3. If the SDT agrees with this, then an appropriate VSL should also be drafted.
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
No
Yes
Yes
No
It is not clear what this list should include. Should the protection changes on the interconnected facilities only be included? Or should it include the protection changes on the adjacent elements? Also, for the changes of power system elements, should those connected directly to the interconnecting bus be included or it should also include changes beyond that?
Yes
No
This 90 day time frame may be too long, since an agreement is required from the interconnecting parties before the proposed protection changes can be implemented.
Yes
Regarding R1, it is not clear what specifically the Protection System Study should include. - According the application guidelines on page 17, it states: "Data used to determine Fault currents in performing the study", what data does this refer to? - Also it states that it should include "listing of the Protection System(s) owned by the entity performing the study that are adjacent to the bus or Element at the Interconnected Facility, and were reviewed for coordination of protective relays as part of the study". It is not clear if it should include a list of all the enabled protection elements and their settings of the protection system package or the package only. Should it include the protection system on the interconnected facilities only or on the immediate adjacent elements as well? - The Application guidelines say it should list any issues associated with the relay settings. It is not clear what should be considered as issues. Does a protection mis-coordination occur only under contingencies (such as primary protection element fails) consider an issue? Do backup protection elements have to coordinate with backup protection elements? Regarding R2, it is not clear what fault current value should be used for the short circuit study. Should it be the total fault current of the interconnecting bus? Or should it be the total fault current of the interconnecting bus excluding the contribution from the interconnected facilities?
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
Reword the Purpose to state as follows: "To allow for the coordination of Protection Systems at

Interconnected Facilities to prevent equipment damage while maintaining proper selectivity during Faults." This phrasing is more consistent with NERC Reliability Standard language where adherence with other reliability standards is not explicitly stated.

No

We agree that applicability of the overall standard should be limited to the Transmission Owners, Generator Owners and Distribution Providers; however, requirements for conducting the Protection System Coordination Study should only apply to the Transmission Owners, Generator Owners and Distribution Providers that have ownership of the protective relay portion of the Protection System. Requirement R1 should read as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System that owns a Protection System shall:"

Yes

Requirement R1 should read as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall:" Requirement R1.1.2 should read as follows: Within 6 calendar months after determining or being notified of a change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.

No

A 10% change in fault current is not an appropriate criterion or "trigger" for relay coordination review. It does not meet the standard's purpose to ensure speed and selectivity requirements associated with protection system coordination. Requirement R2 should read as follows: "For each Interconnected Facility, each Transmission Owner that has ownership of the protective relay portion of the Protection System shall: " Requirement R2.2: LCRA TSC recommends not including this requirement. Requirement R2.3: Should the SDT decide to include requirement R2.2, then rephrase R2.3 as follows: "Where the calculation performed, pursuant to Requirement R2, Part 2.2, indicates a deviation in Fault current of 10% or greater, notify each non-transmission owner of the Interconnected Facility, at which the 10% or greater deviation applies, within 30 calendar days after identification. As an alternative requirement to R2.2 and R2.3, LCRA TSC recommends the following language to R2.1, 2.2 and 2.3: 2.1. Perform a short circuit study to determine the present Fault current values, not less than annually. 2.2. Pursuant to Requirement R2, Part 2.1, provide summary results to each directly impacted non-Transmission Owner entity at the Interconnected Facility, within 30 calendar days after completion of the short circuit study. 2.3 Delete

No

Requirement R3 should read: Each Transmission Owner, Generator Owner, and Distribution Provider that has ownership of the protective relay portion of the Protection System shall provide to each directly impacted Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility, the details (e.g., project schedule, protective relaying scheme types and settings) as follows: The first bullet of requirement R3.1 should read: New installation, replacement with different types, or modification of: protective relays or protective function settings that result in a direct impact on protection system coordination to an entity at that Interconnected Facility. The second bullet of requirement R3.1 should read: • Changes to positive or zero sequence line impedance by more than 5 percent

No

Each Transmission Owner, Generator Owner, and Distribution Provider shall: 4.1. Within 90 calendar days after receipt, confirm acceptance with the summary results of a Protection System Coordination Study, as described in Requirement R1, Part 1.2. 4.2. Prior to the in-service date of any planned change at the Interconnected Facility, confirm the affected Interconnected Facility owners accept the Protection System(s) changes, as described in Requirement R3, Part 3.1

Yes

No

Objectives of R2 and R4 are mostly associated with interchange of information and the associated Violation Risk Factor for these two requirements (R2 and R4) should be LOW.

General Comment: First, as industry comments are considered by the SDT, the standard must continue to take into consideration that the fundamental objective of a protection system is to

prevent equipment damage that may occur as a result of a short circuit by ensuring fault isolation. The secondary objective is to maintain the power delivery capability in the rest of the system during a fault. This must not be compromised. Second, setting of protective relays is an art and finding a balance between dependability and security is already a challenge and may be an area of disagreement amongst owners (in some cases entities may end up "agreeing to disagree"). The standard should not take away the protection system owner's responsibility and right to set its own protection systems by requiring "Approval" from other interconnection entities at the Interconnected Facility. Specific Comments: Title of the proposed standard The title for this standard is misleading since it only applies to locations that contain Interconnected Facilities. LCRA TSC suggests changing the title to "Protection System Coordination for Interconnection Facilities" Terms Protection System Coordination Study: A study that demonstrates existing or proposed Protection Systems maintain proper selectivity while clearing Faults.

Individual

Alice Ireland

Xcel Energy

Yes

No

Yes

The standard does not specify M2 violation reporting responsibility or assignment of violation due to non-responsiveness of the interconnected entity. Clarification needs to be made as to what is considered acceptable evidence that the affected entity received the study results under measure M2. Would a registered mail confirming receipt at an address be considered acceptable evidence; if not what type of document service would be considered acceptable?

Yes

Similar comments on measure M5 as contained in item 3 above on measure M2. This provision should become effective 36 months after the effective date of the standard.

Yes

Yes

Concievably, there could be non-reliability based reasons why an entity might not provide concurrence. An alternate avenue should be considered as allowable, such as the requesting entity working through the RC to obtain response from a non-responsive entity. Similar comments on measure M9 as contained in item 3 above on measure M2. Measure M9 does not account for non-acceptance under R4.3 or R4.1 as restudy or expanded studies may be required and result in a M9 violation.

Yes

1) It appears that clarification is needed in the Application guidelines with respect to the Generator Owners, Distribution Providers and Transmission Owners. If they are the same corporate entity, do the examples indicate as such and would coordination be required as specified? (It is presumed YES but not clear...e.g. GO "R" and TO "S" could be the same corporate entity). Figure 5 implies the letters "R", "S", and "T" refers to different corporate entities since there is a Transmission Owner R and a Transmission Owner S along with a Generator Owner T. If these letters do not indicate different corporate entities, then is it the intention of the SDT that all GO and DP facilities that connect directly to the BES be treated as "Interconnected Facilities"? 2) Additional clarification in the Application Guide (figure 3) is required as it would imply that proof is required that generation on a tapped substation does not pose a risk to the transmission system. 3) The dates and documentation requirements for this standard will require an equivalently complex system or database for tracking in order to prove compliance. From review of the standard it appears that tracking of ~8 dates and associated supporting documents will be required for each interconnection study. Additional implementation time should be included in the standard for proper processes and tools to be in place

prior to perform study or re-study work. 4) Most study work would be initiated by R3.2 and typically involve multiple data requests for varying items and with associated responses providing the information. If each email request needs a corresponding response, then much time will be required to match emails topic for topic to meet this measure. The result will be multiple of same measure for study work, increasing tracking time for engineering. (i.e. more tracking time and less engineering time per engineering FTE). If the measure is to be based on first request to last response then this would be easier to implement. 5) As existing studies will fall under the measures of this document, with no grandfathering, it is likely existing studies will need to be re-evaluated. As a result, consulting services for competent protection engineering services may become limited and may impact the ability in meeting the 36 month requirement. 6) Larger regional studies with interconnection impacts may be the outcome of more localized studies. Such studies could be recommended as a result of R2 of this document or future year models under R3.1. The time-frames specified in this standard may not be sufficient and no exception method is provided for expanded study work. (i.e. -studies beyond what is would be considered typical for an interconnection study).

Individual

Chris Scanlon

Exelon

No

The current Purpose for PRC-027-1 should more clearly and concisely state the purpose of the standard by relating the purpose of the standard to the definition of Protection System Study (the key element of the proposed PRC-027). The statement, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards", is likely to be subject to interpretation by registered entities and auditors alike and cause confusion. The specific Standards should be referenced in a footnote, or the reference should be removed. [For the purposes of this comment and the suggested revision, Exelon removed the reference since we believe this is the best option]. Exelon suggests the following revised Purpose "To ensure Protection Systems at Interconnected Facilities operate in the desired sequence to isolate a fault." In our experience, the term "coordinate" (or "coordination") caused confusion in PRC-001-1 and therefore Exelon proposes that the term be omitted. In PRC-001-1, the term "coordination" was unofficially accepted as either the correspondence or communication between entities (i.e., via email, memo, fax, etc.), or as the time response relationship associated with backup protection elements. Thus, to avoid this confusion and to match to the proposed Protection System Study definition, Exelon removed it from our suggested Purpose statement above. If the SDT believes that the term "coordination" should remain, it should be clearly defined. Given the Protection System Study definition, a suggested definition for coordination would be "operation of Protection Systems in the desired sequence to isolate a fault".

Yes

Agree, all entities should be included if they are responsible for engineering of protection systems protecting BES elements at Interconnected Facilities.

No

Exelon cannot agree to the time frame proposed without understanding the scope of work involved in the required protection system study. The current definition of Protection System Study (PSS) is not clear enough to avoid confusion. To better define the "study" as referenced in PRC-027-1 and to ensure that applicable entities know what they're required to do, the definition of PSS needs to clarify the elements of the protection system and power system conditions the study is run similar to how required Transmission Planning studies are defined. With this in mind, Exelon suggests the following definition for "Protection System Study": A study that demonstrates that existing or proposed Protection Systems operate in the desired sequence for clearing a fault. The study is conducted with a single power system element out of service and all Protection System elements in service, and with all power system elements in service and a failure of a single protective relay, communication system, ac current input, ac voltage input, or DC control circuit (these can be further defined using the information and Table from Order 754). Exelon suggests that "summary results of a protection system study" should also be defined with clear parameters established. Unless the specific particulars are established, Exelon predicts that there will be confusion as auditors attempt to decide whether or not a piece of evidence will qualify as a "summary" of a Protection System Study. This is similar to the ambiguity in the existing revision of PRC-005-1 R1.2 which requires a "summary" of maintenance and testing procedures, yet does not describe specifically what is required. It is our

experience that registered entities and auditors historically have had differences of opinion about what constitutes a "summary".

No

Exelon requests that the conditions under which the required short circuit (SC) study are to be performed should be defined. What future reinforcements should be assumed in the SC model, since the result will depend on these assumptions? In R2, 10% or greater deviation in Fault Current may not be adequate to perform Short Circuit (SC) Study. It should be clearly stated what threshold is adequate to perform SC study successfully, and the SDT should provide some examples how the 'six-month' time frame is considered a "reasonable amount "of time to perform the SC study.

No

In the current draft of PRC-027-1, Requirement 3.1 mandates that for any of the listed network changes, entities must communicate "the details", (i.e., design information to all entities that share the interconnection). Of the network changes/additions listed in the draft, however, some may result in little or no changes to existing protection system coordination settings, thereby having no impact to Protection Systems of other entities. For example, consider a project by a TO to replace a BES circuit breaker at an Interconnected Facility. Assume that breaker failure protection for that circuit breaker will also be upgraded, but that the settings and all protection functions for the new relay remains unchanged from the old system. According to the language of Requirement 3.1, the TO would be required to transmit design information to other entities associated with the interconnected facility even though the project would have no impact to the other entities. This represents one example of a frequently performed project in which design information is not presently shared between entities at an Interconnected Facility. Mandatory compliance with this requirement, as written, could represent a significant burden to the industry by requiring unnecessary communication of design details to other entities, in addition to the added compliance documentation activity, and having no impact to protection systems of the recipients. Exelon suggests that the SDT clarify Requirement 3.1 such that that if a change to an Interconnected Facility is not expected to result in a change to the desired sequence of Protection System operations , the compliance activities required by R3.1 should be waived

Yes

Comments: Although not stated explicitly, this question seems to be asking about R4, Part R4.2. Exelon agrees that concurrence should be reached prior to the in service date for Protection System changes that result from the equipment changes at an Interconnected Facility as described in R3, Part3.1.

No

This question differs from what is required in the language in the draft standard. In Requirement R4.1, the 90 days allowed is for entities to "confirm agreement" with the summary. If an entity must only respond at the end of 90 days, the response could be that they disagree. In this case, discrepancies must be resolved at the cost of more time. Regardless, allowing 90 days for an entity to respond before an entity can proceed with design could cause serious delays to engineering and design processes. However, until we know what is required by a Protection System study, Exelon cannot offer a suggestion for a suitable timeframe for R4.1. SDT should specifically justify the proposed 90-day time frame. Since, a 90-day time frame may not be sufficient to compile all the required design data and results for Protection System Study (PSS) and to verify the Protection Systems are coordinated within the applicable entities.

Yes

None

Individual

Chris Mattson

Tacoma Power

Yes

No

Yes
Yes
No
<p>1. This list does not appear to sufficiently address BES transformers (e.g., autotransformers). 2. There is concern that R3.1 may introduce either an administrative burden to identify and track every change, including those that would not reasonably impact Protection System coordination, or compliance jeopardy if those changes are not identified and tracked. a. For example, the second bullet under R3.1 refers to changes to line spacing. Assume that, during restoration following a Fault, a damaged insulator on one pole or tower is replaced with an insulator one inch longer. Technically, this changes the line spacing. It is doubtful that the SDT intended that this or a similar but less trivial scenario would trigger a Protection System Study; however, the language may introduce compliance jeopardy. Perhaps a similar metric as used in R2.3 could be applied to the second, third, fourth, and fifth bullets. For example, perhaps a 5% change in interconnecting Element impedance from a baseline could trigger a Protection System Study; this approach could be used in lieu of the second and fifth bullets. It seems that R2.3 would address the third and fourth bullets if the short circuit study were conducted before the change was implemented. b. Additionally, the language in the first bullet under R3.1 may introduce compliance jeopardy. For instance, it is possible for an entity to adjust a current and/or voltage transformer ratio and compensate with one or more relay settings such that the primary settings do not change. In many of these cases, there will be no impact on Protection System coordination. While active communication among entities is advised, the potential for fines in this type of scenario does not seem to be appropriate. The emphasis on the first bullet under R3.1 should be on Protection System scheme (e.g., distance, overcurrent, DCB, POTT, differential), primary settings (including time delays), independence/redundancy, and technology (primarily for communications systems).</p>
Yes
Yes
Yes
<p>Is it the expectation of the SDT that Protection System coordination issues may be identified when Protection System Studies are performed pursuant to R1.1.1? If such issues are identified, is it the intention of the SDT that these issues would constitute violations of PRC-027-1, provided that the process described in PRC-027-1 for remedying these issues is followed? Transmission Owners depend on each other for accurate short circuit models. As proposed, PRC-027-1 does not appear to clearly address sharing of short circuit modeling information among Transmission Owners when incremental changes are made within a Transmission Owner's system. For example, incremental changes in adjacent Transmission Owners' systems may result in a 5% change in Fault current at an Interconnected Facility when the changes are considered separately, but when the changes are considered together, the Fault current might change by 10%. While the +/- 10 % change in an Interconnected Facility's Fault current value as a trigger appears to be reasonable, the proposed standard offers no guidance or requirements concerning the accuracy of an entity's short circuit model or the methods used to determine Element impedances. This issue is most pronounced for zero-sequence impedance, and to a lesser extent negative-sequence impedance, since these parameters are used infrequently in system planning studies. It seems that some standardized approach for determining impedance parameters may need to be developed, whether in this standard or in another standard, provided that some latitude is afforded entities based upon sound engineering judgment. In R2.2, why is it not sufficient to simply include the following in the parentheses: "single line to ground and 3-phase for the bus(s) under consideration"? "The formulas in R2 use V for current. For clarity's sake, current should be denoted using the letter I." Under R3.2, if all applicable entities agree to a schedule, was it the intention of the SDT that the agreed-upon schedule could be longer than 30 calendar days? M8 requires that an entity have evidence that other entities received information pursuant to R3.3.1 and R3.3.2. What if, despite due diligence, one or more entities do not acknowledge receipt? Since notification pursuant to R3.3 is after the fact, to be compliant, an entity</p>

depends upon one or more other entities to acknowledge receipt, but there does not appear to be a regulatory requirement for them to acknowledge receipt in a timely manner, only a requirement to confirm that the changes are acceptable within 30 days of receipt pursuant to R4.3. Consequently, if Entity A notifies Entity B of changes pursuant to R3.3 in 15 calendar days, Entity B would have until 45 calendar days following the change to respond. However, by this time, Entity A might not have documentation that it met its requirements under R3.3. Another challenge with R3.3 and R4.3 is that the language seems to assume that both entities will agree to the changes. While this should usually be the case, there may be instances in which the entity receiving notice may not find the changes acceptable. Additionally, the language in R4.3 may influence the entity receiving the notice to deem the changes as being acceptable, even if they are not, in order to meet the 30 calendar day timeframe. Tacoma Power thanks the SDT for including Figure 4 in the Application Guidelines. In Figure 5 of the Application Guidelines, why would it be necessary to check for coordination issues with Protection System settings associated with Breakers A, B, C, and D? Is this language intended to address reverse elements that are independent of communications systems? Is it intended to include bus differential, which would be the scheme commonly applied? Or, is there some other reason? To what extent can this standard be enforced within a Transmission Owner's system? For example, in Figure 1 of the Application Guidelines, in addition to verifying that there are no coordination issues between Protection System settings associated with Breaker A and, say, Breaker F, does the SDT intend that this standard could be construed to grant regulatory authority to audit that a Protection System Study was completed to verify that there are no coordination issues between Protection System settings associated with Breaker F and other breakers within Transmission Owner S's system? While Protection System settings associated with Breakers A and F may be coordinated, Breaker F may not be coordinated with other Protection System settings within Transmission Owner S's system such that Protection System settings associated with Breaker A might also not be coordinated for some Faults within Transmission Owner S's system. It is believed that this type of situation should be rare and that the scope of this proposed standard should be limited to audit and enforcement of Protection Systems at the Interconnected Facilities, as depicted in Figures 1, 2, 3, and 5. Assume that there is documentation supporting coordination of Protection Systems at Interconnected Facilities. However, during a Fault, a Mis-operation occurs, and the cause of the Mis-operation is attributed to mis-coordination, despite good faith on the part of the entities to coordinate Protection Systems. Is it the intention of the SDT that this Mis-operation would be construed as a violation of PRC-027-1? For example, although they are generally addressed to some degree in Protection System Studies, but often implicitly through margins, factors of safety, etc., phenomena such as CT saturation or DC offset are not always directly analyzed in Protection System Studies and could lead to mis-coordination even if Protection System settings appear to be coordinated in documentation. It is not clear what responsibility the TO has if it models a generator's short circuit capability incorrectly. The proposed changes to PRC-001 (proposed version 3) are supported. As a reminder to the SDT, Protection System design and application is part science and part art, and it may be difficult to thoroughly audit and enforce the latter. Tacoma Power appreciates the opportunity to comment on the proposed standard and thanks you for your consideration of our comments.

Individual

David Gordon

Massachusetts Municipal Wholesale Electric Company

No

MMWEC endorses the comments submitted by NPCC.

MMWEC endorses the comments submitted by NPCC.

Individual

Bill Middaugh

Tri-State G & T
Yes
No
We agree with this description and the entities, however the standard's applicability is not written as described in the question. We think that "that require coordination for isolating generation and Transmission Faults" should be added to Section 4.2, Facility Applicability.
Yes
Yes
Yes
No
We believe that there are many instances of changes that can made to Protection Systems as required in Requirement 3, Part 3.1 that don't require coordination between entities but that might be interpreted that the change "modifies the conditions used in the coordination of Protection Systems." Examples are load encroachment settings, communication port settings, etc. We think language needs to be added with regard to "... modifications that impact the coordination of Protection Systems between entities, of: ..." in the first bullet, if confirmation from the other entity is required.
No
We think 60 days is more appropriate. For the receiving party, 30 days may be too short, and for the sending party 90 days may be too long.
Yes
We think there needs to be a time frame associated with the calculation of the percent deviation after the fault duties are calculated. One way to accomplish that would be to eliminate 2.1 and add a 24 month requirement to 2.2., which would require the performance of a short circuit study anyway.
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
Within RTOs and ISOs, entities such as PJM and NYISO perform such evaluations as part of their transmission planning process. See PJM Manual 14-B, Appendix G, section G.7 which states: "PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment." Therefore, Transmission Planners should be considered as an applicable entity for R2 as discussed in #9 below
Yes
We do not believe this requirement has been justified for the several reasons listed below. In addition, the "Protection System Study" definition is too vague as to what it should include. We suggest a separate appendix that lists the items that this study should address. We also suggest that the SDT develop several baseline and change case Protection System Study examples, using a common format. These should be incorporated into an appendix within the standard. a. The format and overall purpose of the baseline study has not been provided. It is highly unlikely that a sufficient Protection System Study has been completed or is available for a majority of the Interconnected Facilities since 6/18/2007 within North America. This is due in part to either no modifications being performed at these facilities or lack of data retention (a study was performed but since it was not a requirement, documentation is not available). To require entities to now perform such studies would be a sizeable undertaking and create a tremendous burden to all entities with little benefit to the entities and the reliability of the BES. For older Interconnected Facilities where no changes have been

made in several decades, no benefit to the facility or the BES would come from perform such a study. b. The only time a Protection System Study should be performed is when a driver is in place that will require a possible relay setting changes. These drivers should be spelled out specifically. For example, if there is substation project work that requires relay setting changes, if the relays are being replaced, if a "tie line" is being re-conducted, etc. The requirement to perform a study should also apply to those "interface" relaying schemes that would normally require periodic review. The requirement for a periodic review will be driven by something other than a system configuration change. This may include schemes that have current operated relaying where the setting of the relay is dependent of fault current level. c. The complexity of such a study is uncertain. In most cases, the "interface" relaying between two TO's or a TO and a GO is very straightforward. In the case of the "interface" between a TO and a GO, the relaying may simply be a transformer differential scheme. In the case of a tie line between two TOs, if the relaying is strictly impedance based, then there is no need to perform a baseline study. In other cases, the study may be more complex. The study may also have to incorporate Protection System devices beyond the Interconnected Facility (e.g. BOP protection for generators, adjacent line or bus protection for transmission facilities). This would increase the amount of time and complexity required to perform the study. How would the SDT define the appropriate protection coordination boundaries for an Interconnected Facility?

No

We disagree with this requirement for several reasons. a. A change in short circuit Fault current, in many cases, does not require relays to be reset. The requirement to perform a Protection System Study for this reason alone will likely provide no benefit when the relay performance is not dependent on short circuit current level. If the relay performance is directly dependent on short circuit level, then a % change in short circuit level may be appropriate. This distinction should be spelled out in R2. b. It is common for relays to be set at 30-50% of the Fault current or 150%-200% of the full load current. A change of +/- 10% in Fault current would have little to no impact on the existing settings and coordination.

No

a. R3 should be rewritten as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider shall provide the following to each Transmission Owner, Generator Owner, and Distribution Provider connected to each Interconnected Facility:" b. Part 3.1 should be modified as follows: "For any change or additions listed below, provide a project schedule and the reason for the project, whether to an existing or new Interconnected Facility or to other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities:" c. Part 3.2 does not read well and is not supported by the explanation in the text box. It references 1.1.1, 1.1.2, and 1.1.3, but none of these parts allow an Interconnection Facility owner to request information from another owner to perform the Protection System Study. We can understand why Interconnection Facility owners need to cooperate in the performance of such studies. This thought belongs in R1. We suggest a new 1.2 (with the existing 1.2 renumbered to 1.3) as follows: "Each Interconnected Facility owner shall provide data requested by another owner and which is needed to perform the study in 1.1, either in accordance with an agreed-upon schedule, or within 90 days of receiving the request." We believe 30 days is too short to require a response.

a. In R4 overall, we concur that agreement does need to be reached before changes can be implemented; however, if there is a disagreement that cannot be resolved by the parties within the time frames specified, a dispute resolution process should be invoked. Otherwise, if an owner disagrees with another owner's results, it has no option but to agree or face a violation of the standard for failing to do so. b. The specific requirement in the question is in part 4.2, not R4. The list of items in R3.1 appeared reasonable. But R4.2 requires agreement to be reached "prior to the in-service date" under R4.2. Allowing agreement to be reached prior to the in-service date could allow one party to unreasonably hold up the schedule. It should be stated as follows: "Within 90 days after receiving the planned changes at the Interconnection Facility, the affected Interconnection Facility owners shall either agree with the changes, or propose alternative changes, stating why such changes are desirable. Failure to provide a response will constitute agreement with the planned changes by the non-responding Interconnecting Facility owner."

See our response to #6 above, paragraph a.

Did not evaluate.

We have the following additional comments: a. FORMATTING: Remove the bullets in 3.1 and replace

with subparts 3.1.1, 3.1.2, etc. b. With regard to R2, we suggest that the Transmission Planner be required to perform the studies described therein, not the TO. Furthermore, there should be a requirement similar to that suggested in our response to #5, paragraph c, that each TP provide data needed by another TP needed to perform the required study. It should also address how potentially different results for the same Interconnected Facility by the several TPs should be dealt with.

Individual

Daniel Duff

Liberty Electric Power LLC

Yes

Yes

No

I disagree with the requirement for a protection system study. From the draft standard: "The SDT has no evidence there is widespread miscoordination between Interconnected Facilities". There are approximately 18,000 generators in the US. Requiring each to perform a system study would result in costs running into the hundreds of millions of dollars. This will result in lower BES reliability as entities transfer funds from other reliability efforts to comply with this standard.

No

No

The phrase "Changes to generator unit(s), including replacements, re-ratings, and impedances" is too vague. Audit teams could read any change as a trigger. Suggested change: "following the replacement or re-rating of a generator, or following any change to a generator which results in a change in impedance".

Yes

No

Smaller entities do not have the staff resources to respond, and must bid, contract, and receive a report. Further, they must also go through a process to allocate the funds. 180 days at a minimum, but ideally a longer period should be in place to allow for the budget process.

No

There is no generator size limit set for this standard. It should exclude generators below a threshold value. Suggest generators with an aggregate nameplate value below 500 MVA connecting through a single step-up transformer.

Individual

Kirit Shah

Ameren

No

We recommend that the SDT delete the last part of the purpose "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to "demonstrate that System performance meets its Table 1 for Category C contingencies" (TPL-001, -002 also have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1.

No

Yes
Yes
(1) In R2 2.1 we request the SDT add “under normal conditions” or “under maximum system conditions” so that it states “Perform a short circuit study to determine the present Fault current values under normal conditions, not less than once every 24 months. “ (2) We request the SDT clarify which Interconnection Facility fault current values are to be compared. If the intent is to keep this general so the entities have the flexibility to compare those fault current values that the entities judge appropriate, please state. Otherwise we suggest adding “Specifically find fault current values flowing into each terminal of the Interconnected Facility for independently applied single line to ground and 3-phase short circuits at its other terminal(s).” (3) We request the SDT change R2 2.2 wording to “Calculate the percent [delete – deviation] change between the Fault current values (single line to ground and 3-phase [delete - for the bus(s) or Element(s)] flowing into each terminal of the Interconnected Facility under consideration) used in the most recent Protection System Study...”. This along with our recommended change to R2 2.1 clarifies the short circuit values that are to be compared. (4) We request the SDT change R2 2.1 to “not less than once every 5 years” for consistency with TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. Our experience is that PRC-027-1 R3 will trigger almost all Protection System Studies anyhow.
No
We recommend the following changes to Requirement 3- (1) Include ‘static wire’ in the second bullet, or more simply state as ‘line impedance changes.’ (2) Include ‘bus arrangement changes’ in the third bullet. (3) Change the fourth bullet to include ‘Additions, retirements, or changes...’ to strive for consistency for generation and transmission.
Yes
Yes
No
We recommend to the SDT that a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: (a) Lower VSL should be 30 days late. (b) Moderate VSL should be more than 30 days, less than a year. (c) High VSL should be more than a year but done. (d) Severe VSL should be more than a year and not done.
(1) We support and agree with the SERC Protection & Control Subcommittee comments. (2) We commend the SDT on their high quality initial draft of PRC-027-1. (3) We recommend that the SDT delete ‘operating’ from the Interconnected Facilities definition because their different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. (4) The SDT needs to improve the application guidance examples by stating what constitutes the Interconnection Facility. The first example clearly enumerates the short circuit locations and values to be compared between the most recent Protection Study and the R2 2.1 value. (5) Application Guidelines Example / Figure 3: The Note should be clarified, or the example should be removed. In terms of regulatory requirements, Breaker-A and B should coordinate with Breaker-C. However, Breaker-C and the Generator relaying does not need to coordinate with Breakers at Station-1 or Station-2 unless the generator meets the requirements of a BES element (75MW or greater). For small generators, protection on the generator to detect faults on the transmission system is for generation protection, not BES protection; as the fault currents would be too small to cause damage to the Transmission System. Generator protection is already covered in Example / Figure #2. (6) Please restate Effective Date more clearly, we suggest “PRC-027-1 shall become effective on the first day of the first calendar quarter [delete-that is] three months following [delete-beyond the date that this standard is approved by] applicable regulatory approvals [delete-authorities],...” to be consistent with the wording of other standards (e.g. PRC-005-2.) (7) Since short

circuit data base models are required to perform the Protection System Study, NERC regions should have a consistent schedule for revising models. Please encourage regions to synchronize their regional modeling calendars to enable entities to have consistent models, especially near region borders, for efficient execution of PRC-027-1 (8) we recommend that the SDT add proposed NERC Standard TPL-001-2 to your list on page 5 regarding the Other Aspects of coordination. It requires short circuit studies in R2.8 for the purpose of determining if the short circuit interrupting requirements are within the interrupting capabilities of circuit breakers. (9) We strongly recommend that the SDT use the term 'change' rather than 'deviation' throughout for consistency and because the latter term is defined as being different from the norm. The new fault current value is now the norm, not abnormal or statistically different. R1 – 1.1.2 and 1.1.3 use 'change', but 'deviation' is then used about a dozen times thereafter in the document. (10) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. (a) The overall process would be less burdensome by changing the R2 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. (b) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. (c) Omitting 'project schedule' from R3 would streamline data exchange. (d) R3-3.1 and 3.3.1 should only be required IF the changes effect the tripping or coordinated functions. Digital relays include numerous settings besides these functions; and these other settings should not trigger a data exchange or study. (e) Streamline the process by measuring dates an entity sends information and receives final agreement. It is burdensome for the sending entity to also track and retain evidence showing another entity received information. Specifically change M2, M5, M6, M7, and M8 to measure the date sent. The other entity's agreement in M9 shows that the overall process met overall time requirements and that the entities coordinated. If an entity demonstrates such a study is not required in R1, M1 should require the other entity to agree. (f) The application guidelines are generally clear and certainly clarify responsibility. We recommend somehow including their methodology in the requirements because it streamlines the exchanged data and clarifies the process in this complex and potentially voluminous undertaking.

Group

FirstEnergy

Sam Ciccone

No

We do not believe the phrase "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is needed and may be confusing to the reader.

No

However, it should be clear the the DP facilities in scope are only those associated with potentially impacting a BES facility.

No

Requirement 1, Part 1.1.1 – Although we agree with the timeframe, the phrase "within 36 calendar months after the effective date . . . subsequent to June 18, 2007" should not be listed as a requirement but rather as part of the Implementation Plan.

Yes

No

Requirement 3, Part 3.1 - We believe that some entities registered as both a TO and a GO may face Standards of Conduct issues if a TO is required to provided the "bulleted" data specified within the Part 3.1.

No answer or comment at this time.

No answer or comment at this time.

No answer or comment at this time.

FE offers the following additional comments: ♣ PRC-001-2 R1 – This requirement is vague and causes

difficulties in consistent interpretations between entities and auditors. We ask the drafting team to revise the wording to clarify the expectations, such as including the types of protection system limitations they should be aware of. Enhancements to this requirement were also suggested in the "NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination" which is attached to the SAR of this project. In their assessment of R1 of PRC-001, the SPCTF said "This requirement is a statement of a highly laudable goal, but this is not specific and enforceable. ... It may be possible to restate this requirement in such a way to be measurable and enforceable. The protective system equipment owners (Transmission Owners, Generator Owners, and Distribution Providers) should be responsible to provide the necessary information to the Transmission Operator and Generator Operator to facilitate their familiarity with the relevant protective systems." We ask the SDT to review this assessment and make changes to PRC-001 and PRC-027 to assure the reliability goal of PRC-001 R1 is met. ♣ With the approval of PRC-027-1, Requirements R3 and R4 will be retired from PRC-001-1 (Requirements R2 & R3 from PRC-001-2, approved as part of the Real-time Operations Project 2007-03) PRC-001-3 will have the same effective date as PRC-027-1. However, in the redlined version of PRC-001-3, the effective date is designated as "the first day of the calendar quarter twelve months following applicable regulatory approval". This is not what is specified in the Implementation Plan.

Group

Southern Company

Antonio Grayson

No

Reference the 'required to isolate Faults '. In some cases the design of the protection system may take more Elements out than the faulted element, such as a transformer differential that trips a transmission bus and then opens a HS Bank disconnect. For this reason we would prefer the term 'as designed' be used. We feel that it is important to identify the Protection Systems that are to be evaluated; perhaps a clear reference to the NERC Technical reference document?

No

No

60 months would be more reasonable for those that have a large number of generators and/or interconnections. Perhaps a tiered approach: 36 months for those with less than 50, 60 months for those with more than 50 but must have 50% done within 36 months?

Yes

When calculating the "+/- 10 % Fault current threshold", the use of bus fault values vs the line contribution values should be clarified.

No

Reference the bullet on Line items; the issue of mutual coupling and/or overhead grd wire replacement or changes should be included. Perhaps change to any change that impacts the positive, or zero sequence impedance.

No

If there is a requirement to agree, what happens if there is no agreement. There must be a resolution process.

No

Within "90 calendar days after receipt, confirm agreement" vs "90 day time frame for responding to a request". Acknowledgement of the receipt and review of a change should be the limit here - agreement with the settings should not be required.

1. The separation of PRC-001-1 in three directions is appreciated. This move was a move in the right direction in our opinion. 2. Whereas the SPCTF may believe that the existing PRC-001-1 was too vague and was not measurable, we believe that the initial draft of PRC-027-1 is overly specificative. Contained within the four listed requirements are actually 11 requirements with 11 different time critical counters that are not to be violated. It is our opinion that equally effective reliability improvement results can be achieved with a standard that is of the form of something in between these two extremes. We propose to eliminate the multiple calendar based time framed requirements

and simplify the eleven requirements into four simply stated requirements. The four requirements, simply, could be: 1) For each Interconnect Facility (IF), perform a Protection System coordination study/review every X years or sooner if triggered by Y. (Y = available fault current change % [r-iii below], system configuration change or other protection system change [r-ii below]); 2) IF owners must notify other IF owners of changes that may affect the other IF owner's Protection System coordination study. (list items likely to affect coordination-this list includes everything in the draft standard R3); 3) TOs are to notify other IF owners if available fault current changes significantly %; 4) IF owners must share & acknowledge receipt and review of their IF Protection System coordination study with other IF owners of that IF. 3. On figure 5 (p. 27 of the draft standard), it seems unreasonable to require that the GO coordinate their protection with that associated for breakers E, F, and G, which are three breakers away from the generator. 4. There is an error on p 5 of the Technical Justification document under Requirement R3. In the first sentence, it is R1, not R3, that requires the IF owners to evaluate the impact to their Protection Systems due to proposed changes by others.

Group

Santee Cooper

Terry L. Blackwell

No

It would probably be good to avoid using the term "coordination" as it can be considered as having two meanings, either the "coordinating" of the exchange of the data or the "coordinating" of the actual protective devices. Coordination should be taken out of the title and the purpose. "To Coordinate Protection Systems" could be changed to "To communicate and exchange Protective System data..." in the Purpose. The title could be changed to "Protection System Interconnected Facility Performance during faults"

No

Yes

Yes

No

In R3, 3.3.1, change the wording to address "changes" instead of "corrections" for "errors." Many changes are made that are not the result of errors. The purpose here should be to communicate changes, and people shouldn't have to debate whether or not to make an "improvement" (not because of an error or misoperation) because it may be construed as a correction of an error.

Yes

Yes

No

The 10 day VSLs are too restrictive in R1.1.1. VSL times should be similar for all requirements. Suggest dates should be as follows: Lower – 30 days late, Moderate – more than 30 days, less than a year, High – more than a year, but completed, Severe – more than a year or not done.

The documenting, notification and replies required in this standard will put a significant strain on the time of settings personnel. While we agree that this coordination of data is very important, any simplification of the processes would help ensure that protection system staff has the time to do other critical protective system work, in addition to interconnection studies. Possible suggestions would be change R2 2.1 to a longer time period, since most re-coordinations are due to changes covered in R3. "Not less than once every third year," would fall in well with the audit schedule. Not less than once every fifth year would match TPL-001-2 draft 5. Also, you could conceivably not have R3 3.3, since those are covered by the statements in 3.1 and 3.2

Individual

John D. Martinsen

Public Utility District No. 1 of Snohomish County

Yes
Comments: SNPD agree with the purpose of the standard; however we disagree with the execution of this purpose. This standard only addresses a very narrow reliability issue. Does the SDT believe this narrow concern needs all the documentation called for in the standard? At a minimum, a Protection System Study, proof that you checked for a +/- 10% Fault current change regularly, and proof that you have communicated with other registered entities on these issues? And this will be for every interconnection. We feels this is regulatory overkill and not indicative of a results based standard.
No
No
Comments: There is no need to have a Protection System Study available for review for every Interconnected Facility. The study is useful only as an intermediate product that leads to relay settings and as a basis for both entities to agree that their planned settings will coordinate. The results based objective is that the registered entities communicate and coordinate together. A simple statement by both entities that they have reviewed each other's settings and agree they coordinate is sufficient proof that the reliability objective of this standard has been met.
No
Comments: SNPD does not agree with this requirement. The selection of a +/- 10% threshold is entirely arbitrary. For instance, some entities will set Z1 to 80%, leaving a 20% margin for error. Some entities will set it at 90%. The SDT should allow entities to decide for themselves when a review is needed. As we stated before, the results based objective is to communicate and coordinate. Not to prove whether the fault current at a certain bus is +/- XX% greater than it was at some time in the past. Furthermore, the SDT itself states there is no proof that failure to coordinate protection systems is causing reliability issues. If entities allow their systems to become uncoordinated, we would expect it to come to light as a Misoperation and be handled under PRC-004. We do not agree it is the TO's responsibility to maintain a short circuit model for other entities. What responsibility does the TO take on if it models a generator's short circuit capability incorrectly? This is a very real concern among transmission protection engineers when attempting to model large wind farms with their proprietary models.
Yes
Comments: SNPD agrees with the list in R3.1. We feel that R2, R3.2 and R3.3 are unnecessary. Instead, the list in R3.1 should act as a trigger requiring both entities to document communication agreeing that coordination exists prior to putting the changes into effect. No communication under R3.3 should be required if the changes restore the system to its original state – replacing a failed relay like for like.
Comments: SNPD agrees that the entities should agree prior to any changes being implemented. The only date of interest, in our opinion, is the in-service date of any proposed changes. If agreement is reached prior to the field changes being made, then that is all that matters.
No
Comments: SNPD does not agree. R4.2 should apply here. R4.1 and R4.3 should be eliminated. If one entity proposes making settings changes, then agreement must be reached prior to implementing the changes. We feel all these timelines are unnecessarily burdensome to remember and quite arbitrary. If one entity feels it cannot get another entity to respond or to reach agreement on coordination, they can always ask their RE for assistance in maintaining the reliability of the system. Since all these activities occurred long before the mandatory standards existed and are covered under the present PRC-001, we do not feel the REs will be swamped with calls if R4.1 and R4.3 are eliminated.
We note that the formulas in R2 use V for current. For clarity's sake, we believe current should be denoted using the letter I
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP, (Occidental Chemical Corporation)
Yes
Ingleside Cogeneration LP agrees that PRC-027-1 should be tightly focused on Fault isolation only.

There are other PRC standards which govern the coordination of UFLS, SPS, phase-distance, and other relay types.
Yes
It would seem like Transmission Planners and Planning Coordinators would have a natural interest in modifications made to relay systems. Their simulations must show that BES performance under various contingencies meets certain criteria. Any information discovered in the course of the Protection System Studies would be of interest to them as well.
No
This requirement assumes that a material percentage of the many thousands of interconnecting relay systems has a problem. There is no evidence of this; and in fact, the Rationale text box for R1 states that the converse is true. This makes sense, as the inter-operation of Fault isolation Protection Systems is a fundamental and well-understood concept – which may not be the case with the more complex relay types. In our opinion, the two-year TO assessment will be sufficient to catch an issue and drive improvements afterwards. Therefore requirement R1.1.1 should be deleted. In addition, we do not agree with the “on or subsequent to June 18, 2007” time frame, since these studies are completed when a facility is built, and/or when a facility is significantly changed, which could quite possibly be prior to 2007. If studies were completed before June 18, 2007, and nothing significant has changed, the study meets the PRC-027 requirement, and/or the TO assessment does not indicate a need, there is no purpose served by repeating the study.
Yes
Ingleside Cogeneration LP agrees that a 10% delta in Fault current is material and would warrant further study. However, we are not sure how these studies would correlate to those managed by Planning Coordinators and Transmission Planners. It seems like these entities would have to be involved in any studies that may result in a change in relay settings or a Protection System upgrade.
No
Ingleside Cogeneration LP believes that the coordination process developed by the project team is redundant with the one established in FAC-002-1. If there is a material change made to a Facility, the process should be captured in a single reliability standard.
No
In general, Ingleside Cogeneration LP believes that a material unplanned change must be communicated to neighboring Facility Owners. However, this should not include an emergency replacement in kind due to a failure. This is a repair only which does not change the characteristics of the relay or the associated BES components – and therefore has no impact on interconnected owners.
Yes
It would seem that M9 should be reworded slightly so that it is clear that the compliance burden is placed on the party sending the confirmation. It seems like it should read “demonstrating the confirmation was sent within the respective time frames” instead of “demonstrating the confirmation was achieved within the respective time frames.” In other words, Requirement 4 compliance is solely for the confirming party to show evidence, not the submitting party.
Individual
John W Miller
Georgia Transmission Corporation
No
The title should state the same as the purpose. Example: "Protection System Coordination of Interconnected Facilities". The purpose is to make each entity communicate protection system and/or facility changes in order to make coordination changes as needed.
No
Yes
No

Using "V" to denote fault current values may help the non-engineer reading the document, but "I" is the common nomenclature for current in the utility industry. The equation in R2.2 should use "I" in place of "V". There is a risk in using calculated fault currents of the most recent PSS and not existing relay settings. If the entity uses 10% margin in settings it will be too late to make settings changes. Should the margin be based on existing fault calculations and existing relay settings basis?

No

The parenthetical comment in R3 should be deleted. R3.1 lists the items that would trigger the need for notification between entities. Once notified of modifications, the entities will communicate documentation needs. R3.2: In the case of major BES equipment failure, there is a more pressing need to notify an interfacing entity that there has been change that could affect fault magnitudes. The 30 calendar days may be too long for such occurrences and 2 business days would be more in consideration. R3.3.1 may interfere with PRC-004-# time schedules for misoperation followups and investigations. R3.3.2: Refer to comment above regarding R3.2.

Yes

Yes

Yes

Meets NERC time frame practice.

Group

Salt River Project

Bob Steiger

Yes

No

No

The requirement to provide a copy of each Protection System Study is an administrative burden that does not reflect the intent of Results Based Standards. Changing the requirement to maintain evidence that Protection System Studies are coordinated and affected entities have agreed to the results of the Studies is adequate.

Yes

Yes

Yes

No

This is too long; 60 days should be adequate

Individual

Dale Fredrickson

Wisconsin Electric Power Company

Yes

No

The previous version, we think correctly, did not include DP's in the applicability. Since the revised definition of the BES is currently awaiting FERC approval, the applicability of this standard to the Distribution Provider function is not appropriate. The relevant entities should be limited to TO and GO only.

No

In some cases there may be many Interconnected Facilities between two or more owners. It cannot be expected that owners will be able to support performing multiple studies in parallel, at the same time. It would be best to eliminate the specified timeframe, and allow the owners the latitude to determine the timeframe based on priorities decided by them. Also, replace the phrases in R1.1.2 and in R1.1.3, "... unless the entity can demonstrate such a study is not required", with "unless the entities involved agree that a study is not required". If the interconnected entities agree that a study is not required, there should be no requirement to document the reasons why a study is not required. Likewise, revise M1 to include as acceptable evidence "documentation that the relevant entities have agreed that a study is not required."

Yes

No

1. R3 should have the phrase "shall notify..." in the requirement, not simply "shall provide ...the details". This should be a requirement for entities to provide a notification to other entities that some changes are being planned which may affect Protection System coordination. 2. The wording in R3.1 is unclear as to the intended scope of the qualifying phrase, "when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities." It should be made clear that ONLY those changes which affect coordination need to be communicated to other entities, whether at new or existing Interconnected Facilities or other facilities. If this is the case, then some of the comments below may not apply. 3. Also in R3.1, the bullets for "changes" in transmission systems and generators should be modified by the word "significant". Likewise, a "replacement" of an Element, or relay, or other device, may not require any change in relay settings, so the wording should be modified by "replacements which require protection setting changes". The bullet for changes to generators should also remove the "re-ratings" term, since a re-rating of a generator typically affects output power, but does not change the impedance. Indeed, there may be many minor changes which fall in the current R3.1 list which may have little or no effect on fault coordination, and therefore should not trigger a requirement for a notification or a study. Also, changes to CT or VT ratios do not necessarily result in a change in primary quantities, so these references should be removed. 4. R3.2 should be revised to require an entity making significant changes to provide the data to the other affected entities, without the need for the other entities to request it. 5. The R3.3 requirement (3.3.1 and 3.3.2) to notify other entities within 30 days for changes made following a Misoperation or failure is too restrictive. A timeframe of 60 days would be more appropriate. Also, as above, these requirements should only be applicable when the changes made have a "significant effect on coordination." A requirement to make notifications for changes unrelated to Interconnected Facility coordination will not serve the objective of increased reliability, and only increases unnecessary compliance documentation. 6. M7 (last phrase) should be revised to "...or absent such an agreement, within 30 calendar days of a request."

No

The requirement to reach agreement on Protection System changes prior to the project in-service date is not realistic and should be removed. While the entity that is initiating a project has a responsibility under R3 to notify other entities in order to perform a study, there is no required timeframe for these notifications to occur. Unless the initiating entity has a requirement to provide data under R3 in a timeframe sufficiently ahead of the in-service date, this is a requirement that may be impossible to achieve.

Yes

The SDT is to be commended for their efforts in what is a very challenging standard to develop. A Protection System Study by definition must assure that Protection Systems are "coordinated" at an Interconnected Facility. However, this standard does not establish any ownership for achieving a complete study. The interconnected entities are only capable of studying the portion of the system that they own. So, each entity performs their portion of the study and communicates it to the other entities. Thus, there is a lack of clarity in the standard about how the complete study gets done and is documented. With the possible exception of the Transmission Owner, no entity alone has the complete system model that is essential for documenting the complete coordination study. There is

also ambiguity on what a complete study looks like, and is subject to interpretation. It is unclear how the supplementary documents previously developed for PRC-001 apply to this standard. In the absence of such guidance, how will consistency be achieved for coordination of Protection Systems on the various types of Interconnection Facilities ? It is suggested that Requirement R4.3 is extraneous and should be removed. If these changes are sufficient to trigger a study, then the timeframe for agreement is already specified in R4.1. We propose that the standard be revised to allow the entities to re-affirm the results of a previous study, when appropriate, rather than needing to perform another study. For example, perhaps the fault current has increased, but the coordination interval between devices is not appreciably changed. The SDT notes in several places in the draft standard (pg 6, 16) that there is no evidence of widespread miscoordination between Interconnected Facilities, nor any evidence of misoperations caused by lack of coordination. This suggests that if this standard is needed, that it should be simpler, less prescriptive, and have greater recognition of the motivation for mutual coordination that already exists. It can be argued that the tasks and time frames required in the draft standard should be left to the entities to determine.

Individual

Rich Salgo

NV Energy

Yes

Yes

No

With such a long time frame for conducting this subject study, one cannot assure that the protection systems are coordinated, and there could be an impending mis-coordination that goes uncorrected. Suggest 12 or 24 months.

Yes

Yes

Yes

Yes

Yes

While we agree the Protection System Studies are necessary to verify coordination of Protection Systems, we believe that the proposed Standard requires more than the necessary amount of documentation, and therefore becomes administratively burdensome. This is contrary to the principles of the Results-Based Standards. We suggest that the evidence be limited to evidence that studies were coordinated and that the applicable entities have agreed to the results of the studies.

Group

Detroit Edison

Kent Kujala

No

It is suggested that “. . . the system performance specified within requirements established in other approved NERC Reliability Standards” be specified so that what needs to be met is clear.

No

No

Why aren't studies performed prior to June 18, 2007 considered acceptable if they're still valid as long as no significant fault current or system changes have occurred?

No

Recommend that the "trigger" be a system change (line, transformer, generator) that results in an impedance change.
Yes
No
Recommend that if protection system changes due to emergencies need not be agreed upon before installation, then this should be stated more directly in the standard.
No
It appears that the "initiator" has 90 days after completing the study to provide the information while the other entity has 90 days to review and respond to the request. Suggest that a longer response time frame be considered since the "responder" may need significant time to review changes.
No
The proposed VSL for R4 appears to imply that the "receiving" entity has no other choice but to confirm agreement. If the "receiving" entity has concerns with the study or changes, both parties should be responsible for resolving the issues.
It is suggested that the standard include other relevant information that could be needed for a protection system study such as critical clearing times determined from stability studies. In Figure 3, what Protection System Studies would be required if the Distribution Provider does not have a Protection System designed to protect BES transmission system elements? Also, please clarify if the transformers in Figures 3 and 4 are BES elements. Also, further clarification, including some examples, would be beneficial to explain what does and what does not constitute "Protection Systems installed to protect Transmission System Elements" by a Distribution Provider.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
LES is concerned with the significant amount of data and information an entity would be required to share as part of R3. As an example, if a CT ratio on a secondary relay with no pilot tripping is changed, but does not change the intended response of that relay, then there is no reason to share that information simply for the sake of sharing it. Entities should be allowed some amount of discretion regarding the information to be shared amongst other entities.
LES recommends additional clarity be added to explain how an entity would coordinate the efforts of the many different protection schemes - for example, pilot tripping, primary, secondary, ground overcurrent, breaker failure, LOP supervised, etc. - to determine only Elements required to isolate Faults are removed from service. Does an entity consider only its fastest scheme, slowest scheme, or all of them? Additionally, is an entity to consider contingencies such as primary or secondary relay out of service, loss of communications, etc.? What about backup tripping? Until the above is addressed, an entity will have a difficult time discerning what exactly needs to be studied. Please take into consideration that system protection is a complicated subject and each entity has its own philosophies on how to do it. Entities should be allowed to use their individual engineering judgment when designing their systems and ensuring it will work to their own standards as well as in compliance with the NERC standards. LES is concerned that there may be potential for mis-coordination between PRC-027-1 and PRC-004-2a. If a misoperation is defined as tripping too much out of service during an event, does the entity become instantly non-compliant with PRC-027-1 since it should have been studied not to do so? Any correlation between these two standards should be considered and clearly defined. LES recommends the 24 month timeframe specified in R2.1 be extended to 60 months.

Historically, fault currents tend to increase gradually over time; therefore, an entity may never see a 10% increase between studies, but will most likely see a 10% increase over a larger timeframe at which point they would never be required to perform a study.

Individual

Mike Weir

Dairyland Power Cooperative

No

The NERC Protection System definition includes more elements than would need to be coordinated at interconnecting facilities (e.g. batteries, chargers). Please consider revising to include only the protection elements that would need to be coordinated to remove Elements from service to isolate Faults.

No

It is unclear how the requirements of this standard apply to entities that fulfill multiple functional roles. For example, an entity is registered as both a Generator Owner and Transmission Owner. In the case where a GO and TO are the same entity is it required to show the same type of coordination?

No

It is agreed that there needs to be a time period for Protection System Studies to be performed after the standard takes affect. However, the length of time is a concern due to the industries existing resources. It would be preferred that the time period be lengthened to 60 months.

Yes

Yes

No

How is it to be handled if two entities do not agree to the same approach?

Yes

Yes

R2, 2.1 "Perform a short circuit study to determine the present Fault current values, not less than once every 24 months." is excessive. Yes, short circuit databases are updated annually or even more frequently at times based on system changes. However, to require a full short circuit study every 24 months is too frequent. Changes on the system don't necessarily warrant a full short circuit study, but maybe a study for the affected area. This is adding an unnecessary burden to the industry.

Group

Western Small Entity Comment Group

Steve Alexanderson P.E.

No

The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.

No

Yes

Yes

No

R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination

studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.

No

R4.1 as written apparently requires receiving entities to always agree with the initial study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that "confirm" be replaced with "reach."

Yes

No

We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.

The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.

Group

Operational Compliance

Ed Croft

Yes

No

Yes

No

We agree with the 10% value, but not with the actual wording in the Standard. (The Standard reads "2.3 Where the calculation performed...indicates a deviation in Fault current of 10% or greater". It is not clear whether this means 10% Fault current deviation above or below, both or just above. We also suggest that specific defined trigger events prompt a Fault current review for affected Interconnection Facilities, instead of fault current reviews being required every 24 months for every Interconnection Facility.

Yes

Yes

We suggest that R4.1, R4.3.1 and R4.3.2 all have a time period of 90 days.

Yes

Yes

All of the questions in this survey should elicit a "yes" response to agree with the Standard. Question 2 elicited a "no" response even though we agree with the part of the standard in the question. The questions in this survey should be worded to ask if we agree with the exact wording of the standard. For example, in Question 4 the wording of the question is different than in the Standard regarding deviation.

Individual

Deborah Schaneman

Platte River Power Authority

Yes

No

No
There is no need to have a Protection System Study available for review of every Interconnected Facility. The results based objective is that the registered entities communicate and coordinate. a simple statement by both entities that they have communicated and coordinated is sufficient.
No
The selection of a +/- 10% change in an Interconnected Facility's Fault current value is arbitrary. The results based objective is to communicate and coordinate.
Yes
Yes
No
We believe the agreement must be reached prior to implementing the changes. This requirement is burdensome on the entity for record keeping and does not add reliability to the BPS.
Individual
E Hahn
MWDSC
Yes
No
No
Protection Systems installed prior to June 18, 2007 should not be required to redo a study because a system study should have been performed prior to installation based on the interconnected configuration at that time. The interconnected systems will change over time and redoing studies will raise more questions on assigning responsibility for changes beyond the control of the protection system owner. For protection systems installed prior to June 2007, TOs should only be required to show a study was performed and coordinated with appropriate interconnected entities.
No
Every TO should not be required to perform a short-circuit study every 24 months if there were no significant changes to that TO's BES facilities. Changes in adjoining interconnected BES systems could change short-circuit duties for an adjoining TO's system. The TO whose BES changes should be responsible for performing short-circuit duties on all adjoining systems as part of Requirement R3. In addition, FAC-002-1 requires TOs to coordinate with TPs and PAs in the assessments of proposed new facilities, including evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission through steady-state, short-circuit, and dynamics studies.
Yes
Yes
No
More time than 90 days may be needed to reach agreement for complex system changes or because of conflicting study priorities. Allow more flexibility for the parties to agree to a time, not to exceed, e.g. 180 days.
Yes
The standard requires more documentation than is necessary and providing a copy of each Protection System Study is burdensome and would not result in better performance. It should be adequate to document that studies were performed and that affected entities have agreed to the results.

Individual
Angela P Gaines
Portland General Electric Company
Yes
No
Yes
Yes
No
No, Add facility ratings and define transmission line impedance tolerance (see question 9 response)
No
No, see question 9 response
No
No, It depends upon what constitutes a Protection System Study (see question 9 response)
No
No, Severe VSL for lateness should only apply to R4.
This standard, as written, requires an inordinate amount of documentation that this not in line with current fault study and protection coordination tools. When combined with the timelines, this will require a complete rework of the existing processes used for protection coordination and an additional full time protection engineer. We have no history of misoperations on interconnecting lines or of backup protection on such lines to justify any additional effort to document coordination. R1 leaves open to interpretation what constitutes coordination, with many unanswered questions. What is an acceptable coordination margin? How many contingencies need to be considered? Does loss of communication need to be considered? For the evidence, would an exception report showing no coordination intervals are violated be acceptable for the "summary results of each Protection System Study"? Will the responsibilities outlined in the Application Guidelines be included as part of the final standard? These may not be in line with current practices. How will this requirement be audited across utilities with different coordination practices? R2 requires significant cooperation between interconnecting utilities, with each keeping track of what fault currents are being used by the other. This is not in line with the use of joint system models, allowing more frequently updated fault currents to be used. Currently, the individual system models are updated by some utilities daily then they are reconciled at least annually. Protection System Studies can be run any time in between model reconciliation, with all local changes accounted for. R3.1 does not provide guidance on the timing of notification for changes; the measure M6 indicates this is for future changes, but the requirement does not. Protection engineers are rarely notified in advance of transmission line changes resulting from such things a road widenings and pole replacements. Providing this information to neighboring utilities in advance will require significant changes to line design processes. Thresholds must be established to rule out minor transmission line changes that do not significantly impact the line impedance (and thus the fault current); perhaps a 10% change in impedance would be more appropriate than the general "changes to line lengths and/or conductor size or spacing". This requirement should also include changes to facility ratings to ensure PRC-023 compliance. R4 requires a significant change to work practices to support capital construction schedules and allow interconnecting utilities 30 days to review changes. The schedule laid out does not account for disagreements that lead to back-and-forth prior to achieving agreement. This requirement grants power to neighboring utilities to halt construction activities which could, in turn, create compliance violation of other Reliability standards.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes

No
ATC is not aware of additional functional entities that should be included.
No
ATC does not agree with the time frame proposed. The existing requirements in PRC-001 do not require protection system studies with Distribution Providers. As such, even though studies have been completed there may be no package (documentation) to support an audit. This requirement assumes that, if there is no existing fault study, one needs to be completed. If there have been no changes in short circuit or protective schemes, allow for completion of the studies based upon prioritization using voltage class and loading level.
Yes
ATC does agree with the premise of the a 10% change but feels that the SDT needs to provide a clear definition of which fault current must change 10% to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in feed current and relay settings.
No
ATC does not agree with the list as written and recommends the following changes: ATC suggests that Requirement 3.1 bullet 2, be revised as follows: Changes to line lengths and/or conductor size or spacing that result in significant impedance changes. As an example, an interconnected line may need to relocate a pole because of a road move. This may alter slightly the length or spacing of the line but does not result in a change to the impedance. If no impedance change occurred, no relay settings need to be changed and there should be no additional coordination. ATC suggests that Requirement 3.1 bullet 3, be revised as follows: Additions, removals, or replacements of transmission system Element(s) that is significant. An Element may be replaced with an equivalent device that does not require a relay setting change. If no relay settings need to be changed, there should be no additional coordination.
Yes
No
ATC does not agree with the 90 day time frame. ATC also has the following recommendation: Requirement 4.2 states that Interconnected Facility Owners confirm that coordination is agreed to prior to placing equipment in-service. ATC believes that R4.2 is adequate to cover coordination. Therefore, the SDT should strike R4.1 and R4.3.
No
The VSLs, in general, are much more severe than the risk to the BES and should be rewritten to more accurately reflect the risk. For example: if a BES Element is replaced "like for like" with no material impact to the associated settings and a failure to notify by more than 30 days occurs, the issue is assigned a Severe VSL yet there was no effective change to BES reliability.
In general, ATC agrees with the need to modify PRC-001. However, PRC-027 as written expands the scope of PRC-001 by including Distribution Providers (DP). The SDT, on both page 6 and 16 states that there is "no evidence of widespread miscoordination between Interconnected Facilities..." They further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperation." Based on the above statements, ATC questions the need for the level of prescription in the standard. ATC asks the SDT to update the numbering for measures to match the requirement numbering. Reliability Standard TPL-001-2, which has been approved by NERC BOT, requires short circuit analysis. ATC believes that PRC-027-R2.1 is duplicative.
Group
Pacific Gas and Electric Company
John Hagen
Yes
No

No
PG&E we believes that the 6 calendar month time frame in requirement R1.1.2 is too short and should be extended to 12 calendar months
No
The requirement to run the fault study to determine if there is any 10% change is only required once every 24 months per requirement R2.1. But if you run a batch study and find a bunch of 10% changes, you only have 6 months to do all the coordination studies. We think a 12 month window for performing the coordination studies is more appropriate.
Yes
Yes
No
12 month time frame may be required to resolve the technical issues that typically prevent agreement
No
do not line up with proabability and potential severity
Group
Northeast Power Coordinating Council
Guy Zito
Yes
No
From a reliability perspective, the Applicability Section of PRC-027-1 should not include the Distribution Provider because the TO is responsible of coordination of the protection with the DP.
No
Agreed that a change in fault current is a method to trigger a coordination study, but a 15% threshold would be more efficient (+/- 15 %). Clarify where the fault is to be applied and where the deviation is to be observed. One possibility is to apply the fault at a bus at one end of the tie and then determine the deviation in the current in each element connected to that bus.
No
DP must be excluded from R3. See the response to Question 2.
Yes
What happens when consensus is not reached between two parties? The TO should have the responsibility for coordination.
Yes
For studies of an entire system or all of its interconnections, those persons doing the study should only be responsible for reviewing the study results for those interconnections in which they participate. The wording in the text demands that the results be agreed with. The text should be reworded to require a response (not necessarily agreement) within 90 days and only pertain to the portion of the study applicable to interconnections participated in.
Yes
1. Referring to the Example Process on page 22, it should not be the responsibility of Entity B to propose revisions. It should be the responsibility of the Entity in the better position to propose a revision to propose the revision. There needs to be flexibility as to who is obliged to come up with a revision. 2. Regarding Fig. 2 and Fig. 5 in the Application Guidelines, it is important that the expertise of each entity involved in an interconnection be used to ensure that there are no coordination issues.

For example, Generator Owners and Transmission Owners. 3. Application Guidelines Fig. 3 requires the TO to verify that the DP's and the GO's protection systems coordinate with the TO's, even though the GO doesn't connect directly to the TO. It should be the DP that checks coordination of the GO with the DP for faults on the transmission side of the DP's substation transformer, and the TO that checks coordination of the DP's transmission protection with the TO. If all of the transmission protection is back at the GO (in other words the DP has installed no transmission protection at its sub) then to do as this app guide suggests the TO will require an accurate short circuit model of the DP's system between the GO and the TO. It would require that the DP keep the TO continuously appraised of changes to the DP's system that impact the short circuit representation. Considering the proliferation of distributed generation being interconnected to distribution systems the burden should be on the DP not on the TO supplying the DP to verify coordination. The scope of the text "...generator protection systems..." should be narrowed so a TO or DP is not responsible for the coordination of devices it doesn't own, maintain or set.

Individual

Rick Koch

Southern Minnesota Municipal Power Agency

I agree with and support the comments of the MRO's NERC Standards Review Forum (NSRF).

Individual

Don Schmit

NPPD

No

Suggestion: Remove "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" since there are other standards that are or will be in place otherwise it sounds like the other standards must have evidence included for this standard documentation as well. Perhaps this standard is not required if the other performance standards are adhered to or have portions of this draft standard included in them.

No

This applicability needs clarification. How does this standard relate to the definition of BES? Does including Distribution Providers mean an entity that does not own a transmission protection system is included under this standard? There needs to be clear understanding that radial feeds on load serving transformers such as 115/69kV or 115/34.5kV transformers and low voltage feeders are not included in this standard. Perhaps NERC needs a program to evaluate/identify all functional entities and determine if they should be registered and thus applicable and not have utilities try to determine the status of other utilities or functional entities. Clarify if the Transmission and Generator owner are the same utility how sharing of information is documented or confirm that this relationship means the documentation is not applicable in this standard.

No

To mitigate compliance risks for various types of data formats for existing studies and studies older than June 2007 this standard will likely require utilities to go back and update all data so that it meets the requirements and description of evidence in the application guidelines when the requirements become enforceable. This could likely take longer than 3 years. I would recommend more time such as 6-10 years (time depends on the number of applicable system ties as well)

No

Monitoring for a 10% change in faults could trigger studies that are not needed and it is not necessarily a good indicator settings updates are needed. It would be more practical to require a

review of settings on a set interval (5 years) or as required by R3.
No
Section 3.3 should clarify if the corrections change the coordination then other entities should be notified.
No
Recommend the drafting team should consider several scenarios to help determine issues that will arise with putting into practice this standard with the time lines included. Some scenarios I can think of are: 1. who is liable or fineable if a required approval reply for a protection study is not made in a timely manner to a Transmission owner. It is imperative not to hold a utility responsible for another entities lack of timely responses. Theses issues will create murky situations when the Transmission owner does not have control over external entities ability to respond to notifications of changes within specified times. 2. If a Distribution Provider is not registered is the Transmission owner responsible for getting a reply or approval of a protection study?
No
This requirement does not allow for various scenarios or conditions in the process of doing business. For example, multiple phased work or longer lead time projects where designs may change. It would be better that there be verification that studies were performed prior to in-service dates rather than tracking detailed time lines which could likely be complex and difficult to judge for audit start and end dates.
No
The time lines monitored down to 10, 20 or 30 days appear to be impractical in terms of monitoring for facility owners and in terms of auditing by compliance entities. This diverts the focus or sharing the data in a timely manner prior to project in service dates.
On page 6 and 16 there are statements such as "no evidence there is widespread miscoordination between Interconnected Facilities..." and on page 16 "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." Clarify what the need is for this standard? This proposed standard significantly increases the record keeping requirements and subsequent resources needed for each Facility owner but does not appear to have a justification. I find the numerous time lines will create significant confusion and very complex data retention practices that will be difficult to track and difficult to audit. It appears the focus is more on time lines and the likely result is the content of the shared information will likely suffer due to the burden of tracking communications between entities. This draft standard includes time lines ranging from "prior to in service date, 30 days, 60 days, 90 days, 6 months, 2 years and 3 years". I suggest fewer and longer time lines with the focus on if the sharing of information took place and not on when did it take place. The SDT statement below should be generalized to the standard as a whole: "The SDT believes that it is not appropriate to specify a single time frame for providing the details of the wide variety of conditions listed in Requirement R3, Part 3.1 that may be associated with a particular change. This is because the SDT sees the entity initiating any change as having the incentive to move the process along in a timely fashion in order to both keep the associated project on schedule and confirm the changes are acceptable "prior to the in-service date," Clarify the size of generation for Distribution Providers that would make this standard applicable for all involved entities. I would expect that the BES phase II definition or registry criteria would be referenced.
Individual
Brian Evans-Mongeon
Utility Services
No
The purpose should specifically state whether or not this standard applies to BES Elements or all Elements. In consideration of other PRC reliability standards, this standard uses language that implies applicability to all Elements. Under the NERC Standard Development Process, standards are only to be applied to BES equipment, unless the applicability language specifically states a broader application. This standard implies it but does not specifically state it. The standard should be modified to clear up any confusion.
No
However, using the broad term "Protection Systems", this SDT is broadening the scope of the

standard beyond the BES. Due to the recent direction in Project 2007-17 for PRC-005-2, Protection Systems has been expanded to include systems beyond the definition of the BES. This project should limit the applicability for the DP to "transmission Protection Systems" as identified in PRC-004 and 005-1.

No

This requirement if left as is, would create a potential double jeopardy situation if a violation occurs. Under FAC-002, entities already have the obligations to communicate and coordinate the integration of new, replacement, or upgrades on existing facilities. We view this requirement to be a duplication of that standard and creates a double jeopardy situation if a violation were deemed to have occurred.

No

See comment to Question 5.

No

Group

MRO NSRF

WILL SMITH

Yes

The last part of the purpose, "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" is vague and open-ended. The NSRF recommends that the SDT refer to the TPL standards if the intent is to limit responsibility for correct coordination to studied system contingencies

No

The standard includes the definition of Interconnected Facilities as BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities. It is unclear how the requirements of the standard would apply if a registered entity would fulfill more than one functional entity role. For example if a registered entity was both a Generator Owner and Transmission Owner would the requirements of the standard apply to the interconnection of the generator and transmission facilities? It is recommended that the standard be modified to provide clarity for this situation.

No

If an entity has a Protection System Study performed prior to June 18, 2007 that meets the requirements for the study specified in PRC-027-1 and there have been no changes to trigger a new study as specified in PRC-027-1 (that have occurred) the study should be acceptable for compliance with the standard. It is suggested that the requirement R1, sub-requirement R1.1 be revised by removing the phrase "that was performed on or subsequent to June 18, 2007." The NSRF questions if 36 months is ample enough time for large company to get all studies done within 36 months. Unless R1.1 is revised to mean all studies regardless to when it was performed.

The NSRF recommends that a clear definition of what fault current must change 10 % to trigger the notification requirements and initiation of a protection study. Fault current on an interconnecting line may change very little even though bus fault contributions from other lines may have increased considerably, affecting in-feed current and relay settings. It would be easier to implement a time-based periodic review of settings every 5 – 8 years (or sooner if required by conditions in Requirement R3). R2 is redundant and could subject entities to double jeopardy in conjunction with the new TPL standards which will require annual short circuit studies and NERC studies should not be duplicated to avoid double jeopardy. At a minimum, the 24 month requirement should be changed to at least every 2 calendar years. This would align with the annual requirement for the TPL standards. The new TPL standards are in limbo with FERC's rejection to footnote b.

Yes

No
The NSRF agrees in general but questions how to handle situation where neighboring utility are unable or unwilling to meet required timetable? Recommend the SDT explain the process for conflict resolution. Requirement 4.2 seems to mandate agreement with proposed changes which seems to go beyond the scope of the standard which is stated as "to coordinate Protection Systems". It is suggested that this requirement be rewritten to require agreement that proper coordination will be maintained when the changes are implemented. In a similar way requirement 4.3 should be rewritten.
Yes
Yes
Recommend that the wording of R2 need be modified to allow a grace period for implementation, as was done in R1. As written, R2 requires an immediate short circuit study, even if no protection system study is required by R1.1.1. The SDT, on both page 6 and 16 states that there is "no evidence there is widespread mis-coordination between Interconnected Facilities..." They further state on page 16 that "Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." Why, then, is this standard even needed? It adds an onerous burden of record keeping on each Facility owner without justification for doing so. Since these are still zero defect standards, should exceptions be included for required operational replacements due to events (e.g. such as storms or immediate equipment replacement). When the lights are out and a technician replaces a CT or VT with a slightly different ratio but compensates by altering the relay settings, there is no way to perform an instant system protection study when the equipment change out was required to support system reliability. The NSRF understands that a "planned" change be studied before hand, but how will this be viewed when a change is needed that is "unplanned"? Please clarify
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
PRC-027 appears to have been written exclusively for vertically integrated power companies, and there is no justification for making the proposed standard applicable to independent GOs. The only role an independent GO fulfills in isolating faults is to trip the breaker if the generator or GSU has a problem; everything involving sequencing is in the Transmssion Owner's (TOs) or Distribution Providers (DPs) system. Independent GOs are owned by separate legal entities than the applicable TO or Distribution Provider [DP] to which they are interconnected. Such GOs do not have the capability to perform the type of TO/DP system studies that appear to be contemplated by the SDT. The actions required of independent GOs should be to perform Protection System maintenance and supply data to other applicable entities, per existing standards PRC-005-1 and PRC-001-1.1, respectively.
No
Applicability to GOs should be limited as stated above in question #1.
No
As noted in the response to question #1, TOs and DPs have the data and the capability needed to perform the studies that appear to be contemplated by the SDT.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.
No
See comment in question #1 above.

The cutoff date of 6/18/07 for grandfathering of studies may be appropriate for TOs and DPs in light of changes over time to their systems, but the studies that originally established GO relay settings would still be valid where the equipment has stayed the same. For the reasons discussed above, there should be no applicability of PRC-027 to independent GOs, and no changes to PRC-001-1.1 because the applicable requirements.

Group

SERC Protection and Control Subcommittee

Joe Spencer

No

a) Recommend under Purpose, deleting: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003R1.3.7 already requires the entity to "demonstrate that system performance meets its Table 1 for Category C contingencies" (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. b) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to "Protection System Interconnected Facility Performance during Faults". Also recommended is to change the Purpose to read "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults." c) In PRC 027, using the term coordination should only be referenced when referring to the technical aspects of the relay coordination within a requirement when applicable. (In the current PRC 001 standard the meaning of the term "coordination" has, and still is, interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between entities).

No

Yes

Yes

a) In R2 2.2, replace the term "deviation" with "change." (Note: For this calculation, all that is required is to calculate percent change. For example, Webster's dictionary definition of "deviation" is: 1) a variation that deviates from the standard or norm; "the deviation from the mean" 2) the difference between an observed value and the expected value of a variable or function.) b) In R2 2.2, replace the term "present" with "new" and the term "most recent" with "previous". Also reflect this terminology change in the %Change equation. (The use of the terms "present" and "most recent" can be perceived to be the same.) c) It is also recommended that "V" for value be replaced by "I" for current. d) In R2 2.1, please add "new", delete "present" and add either "under normal conditions" or "maximum system conditions" so that it states "Perform a new short circuit study to determine the Fault current values under normal conditions, not less than once every 24 months.

No

a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3 3.3.1, change requirement to read: "Changes are made to a Protection System as a result of findings during misoperation investigations, commissioning, or maintenance activities." (The current wording implies that all findings are due to errors. The reference to errors should be removed and the emphasis of this requirement needs to be placed on "changes" made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)

Yes

Yes

No
We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 30 days late. • Moderate VSL should be more than 30 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.
a) Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." For Requirement R1-1.1.2, recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required". b) The standard uses different formats for identifying deadlines. Sometimes "days" are used and sometime "months" are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1, which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual requirements where time schedules are involved, the wording of the requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the requirement whereas R1-1.2 references the time schedule at the end of the requirement. Recommend using a standard wording format and list the time horizons in the beginning of the requirement in all requirements that have time requirements involved. For Requirement R1-1.2, recommend changing to read: "Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions)." e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing the R2 2.1 to "not less than once every 5 calendar years" which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2. iii) Omitting "project schedule" from R3 would streamline data exchange. f) Delete "operating" from the Interconnected Facilities definition because different functional or corporate entities sufficiently capture all of them. We also suggest defining the singular Interconnection Facility, rather than the plural. "The comments expressed herein represent a consensus of the views of the above named members of the Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Individual
daniel
mason
Yes
No
Yes

Although the timeframe appears reasonable, the more basic question about the necessity of the documentation requirements needs to be reconsidered.
No comment
No
Do not agree with blanket inclusion of replacement of the generator step-up transformer(s) on this list.
No
Each entity has its own philosophy and standards for Protection System design. In providing agreement to a third party design, a question of liability is also opened up. R4 should be changed from requiring agreement to requiring notification. There is enough incentive for entities to resolve material disagreements on Protection System design without the need for regulatory intervention. Regulatory involvement should only take place when business conditions call for it. Otherwise the result is higher production costs with no reliability benefit.
No
Do not agree with the need for documentation of "agreement with a Protection System Study" between entities. See Question 6 response.
No comment
Individual
Rowell Crisostomo
ATCO Electric
Yes
No
Yes
There are too many timelines that are hard to keep up with. The drafting team should reduce amount of timelines to a manageable amount.
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
Yes
No
Yes
Yes

No
Illinois Municipal Electric Agency (IMEA) recommends language be included in R3 (and elsewhere if needed) to clarify the R3.1 "generator unit(s)" is not applicable to a 20 MVA or less unit or behind-the-meter generation.
Yes
Yes
IMEA recommends language be included in 4.2 Facilities to clarify the standard does not apply to a DP protective device that only detects a fault on a transmission element and does not trip an interrupting device that interrupts current supplied directly from the BES. To minimize misinterpretation and potential impact on small entity resources, it would strengthen the standard if Section 4.2 Applicability language specifies the standard does not apply to a DP that does not own a BES Element/Facility.
Individual
Rhonda Bryant
El Paso Electric Company
Yes
No
Yes
It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: • Study performed in Year 1 shows a 5% deviation • Study performed 12 months later (in Year 2) shows a 5% deviation • Study performed 12 months later (in Year 3) shows a 5% deviation [Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Yes
Yes
No
EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities. Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. Additionally, the proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond to study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.
Group
Colorado Springs Utilities
Jennifer Eckels
Yes
There are cases of weak system interconnected facilities where proper coordination may not be

achievable economically, except by severing the interconnect. Allowances should be made for these cases to prevent the severing of weak systems to meet this standard.

No

The wording of the text suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are usually contained in different functional or corporate entities it suggests much more documentation, and needs clarified.

Yes

No

In order to avoid burdensome paperwork of traditional fault study values and existing fault study values, common thresholds should be determined for initiating a review. Common thresholds can be common device ratings, or agreed upon levels at interconnects. As in Facility ratings, each owner should have device ratings for device capacities and can include short circuit ratings, which if exceeded can initiate a review.

No

Specific project schedules can potentially cause violation of other requirements. A proposed change of conductor spacing, which can be interpreted as a change of one transmission structure requires notification to other entities, which we feel is excessive. Re-rating of generators rarely changes the protection, impedances or coordination involved. It is common to re-rate units depending on external factors to the generator which also provides excessive reviews and project schedule notifications. This section also implies notifications must be made after like and kind replacements of equipment found during misoperation investigations, but not those found during testing. On larger systems this requirement would be difficult unless notifications were made more than twice a month, which would require a large tracking system of who, what, and when information is sent to interconnected utilities.

No

This requirement seems to create a paper work burden that will add cost and lengthen the process of any and all transmission changes, unless there is some size significance added to the requirement under which a reduced process is involved. The maximum amount of paper work to complete must be assumed, unless there are specific limits set to restrict an overreach in how the regulation is applied.

No

Due to construction schedule requirements a 30 day approach should be taken.

No

If the requirements are not reasonable, the VRFs and VSLs are also not reasonable.

The wording of the text under Applicability suggests that Interconnected Facilities include coordination and documentation of Transmission to Distribution interfaces. Since these are often located in different functional or corporate entities we feel this would require more documentation, and therefore needs clarified. There are no specifications on what constitutes a significant change to a Protection System; is it a CT ratio change, a relay replacement, or anything to the whole system? For example, would a single structure replacement require notification as a line spacing change? The wording sounds good but lacks specifics that would make this a workable standard.

Group

ISO RTO Council SRC

Charles Yeung

No

Is the intent of the coordination that is expected limited only to those protection systems related to intertie facilities between facilities owners ? Or is the intent of the proposed standard to require coordination of protection systems to take into account outage and/or operating conditions between facilities owners beyond the immediate intertie facilities? In other words is this coordination requirement expected to be applied to relays that may not be directly involved in protection of intertie equipment?

Yes

Depending on the intent of the requirements as questioned in the comment to question #1, it may be necessary to include planners to provide data for contingent and varying operating conditions to coordinate relays beyond those dedicated to intertie facilities.

Yes

Yes

Yes

Yes

Yes

Yes

The SDT recognizes that Requirement R1 falls outside the scope of Project 2007-06 and proposes that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. Left unaddressed, entities may be reluctant to vote to approve the PRC-001-2 changes. Changes made to a standard can cause unforeseen or unintended consequences that cannot be addressed because of limitations in the scope of the project. The SDT has no ability to address the matter without getting a change in scope of the project. This is a concern that applies to ALL standards changes as the industry seeks to revise and improve the NERC standards. A change in the Rules of Procedure or the Standards Development Procedures must be in place to recognize and deal with such occurrences. The SDT is also concerned that these proposed requirements are not conducive to NERC's stated goal of making the reliability standards more "results or performance oriented". Although many of the actions embodied in the proposed requirements should be performed, they are administrative in nature and do not in and of themselves provide results that will impact reliability. The industry needs to discuss and come to agreement on what reliability standards should look like in order to meet the NERC stated goal. The SRC also believes these requirements are not applicable for entities operating in the ERCOT Interconnection.

Individual

Steven Powell

Trans Bay Cable

No

The language "...remove from service only those Elements required to isolate Faults..." is problematic. Taken literally; only the faulted Element may be isolated, and any adjoining buswork or lines (separate Elements) must remain energized; even the result is no change in the loss of load or capacity. We suggest ""To coordinate existing Protection Systems..." to ensure that this is not interpreted as a construction standard requiring additional Protection Systems.

No

Yes

Yes

No

Comments: R3 seems confusing and redundant. R2 designates TOs as the responsible party for coordination studies and this seems appropriate. We believe that R3 should focus more on DPs and GOs complying with requests from TOs. A clear line of delineation from TO request seems more straightforward.

No

Comments: R4.1 as written apparently requires receiving entities to always agree with the initial

study, even if they see flaws that would lead to miscoordinating Protection Systems. Suggest that "confirm" be replaced with "reach."

Yes

No

Comments: We note that for R1.1.2 VSLs ratchet up very quickly despite the SDT contention in "guidelines and Technical Basis" that they have no evidence of widespread miscoordination between Interconnected Facilities and that miscoordination is not the predominate cause of reported Misoperations. The 10-20-30 day ratchet just seems arbitrary.

Comments: The comment group agrees with the WECC Position Paper that the standard as written requires excessive and burdensome documentation that is not needed to demonstrate coordination.

Individual

Daniela Hammons

CenterPoint Energy

No

The proposed term for Interconnected Facilities, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "BES Facilities that are electrically joined by one or more Element(s) and are owned by different functional, operating, or corporate entities." CenterPoint Energy believes Interconnected Facilities should be defined in reference to NERC registration and recommends changing the definition to "BES Facilities that are electrically joined by one or more Element(s) and are owned by different registered entities."

No

(a) The proposed term for Protection System Study, shown on page 2 of 27 of PRC-027-1 Draft #1, is defined as "A study that demonstrates existing or proposed Protection Systems operate in the desired sequence for clearing Faults." CenterPoint Energy recommends Protection System Study instead be defined as "A study that demonstrates Protection Systems operate as desired for clearing postulated short circuit Fault events." (b) CenterPoint Energy believes a 36 month implementation to have a documented Protection System Study completed for each Interconnected Facility is overly burdensome, unless certain Interconnected Facilities are exempted. CenterPoint Energy recommends exempting Interconnected Facilities that are serving only load and that are connected by no more than two transmission line Elements that are operating between 100 kV to 200 kV. Many of these Interconnected Facilities have fault-proven, time-proven protection system set points. Additionally, Draft #1, on page 5 of 27, notes that protection system misoperations related to coordination issues are addressed by PRC-004.

Yes

No

(a) Requirement 3 includes providing schedule information and project details to generation entities. There may be established market rules that provide for what information can be shared with competitive entities. (b) Requirements 3.1 and 3.3, with examples of what system and equipment changes require coordination, appear overly broad. Such requirements should only be "if applicable". R3.1, for example, specifies changes in line length. Certain changes of line length are immaterial to protection system set points. R3.3 requires coordination for the replacement of failed equipment. Replacing equipment "like function-for-like function" should be excluded from this requirement.

Group

Tennessee Valley Authority

Dennis Chastain

No

a) The term "coordination" should be removed from the new standard Title and Purpose. Recommend changing Title to: "Interconnected Facility Protection System Performance During Faults". Also recommend changing the Purpose to read: "To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those elements required to isolate faults." b) Recommend under Purpose, deleting: "while meeting the system performance specified within requirements established in other approved NERC Reliability Standards" as it is superfluous and could cause duplicative or conflicting work. The purpose without this clause is clear, concise, and consistent with the rest of the 1st draft of this standard. The resulting coordinated Protection System must meet 'the system performance specified within requirements established in other approved NERC Reliability Standards' and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1. For example, TPL-003 R1.3.7 already requires the entity to "demonstrate that System performance meets its Table 1 for Category C contingencies" (TPL-001, -002 have similar requirements). Entities perform such work for TPL, and need not repeat it for PRC-027-1. c) In PRC 027, the term "coordination" should only be referenced when referring to the technical aspects of the relay coordination within a Requirement when applicable. (In the current PRC 001 standard the meaning of the term "coordination" has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as "relay coordination" and the second is viewed from an inter-communication aspect as "coordination of information" between entities).

No

In some instances end-use customers, such as a large industrial load, take service delivery through an Interconnected Facility. It is not clear that the draft standard covers coordination between a TO and an end-use customer (not registered as a TO, GO or DP) who takes service via a BES Interconnected Facility.

No

"Protection System Study" is a new term being introduced with this standard. Since industry documentation of protection system coordination reviews are conceivably available from both before and after June 18, 2007, precluding coordination reviews performed prior to June 18, 2007 from acceptable compliance evidence could greatly increase the workload of protection system engineers during the proposed 36 month time period. Note that there is a possibility of overlap with the "Order 754 request for data" response period. The rationale statement for R1, Part 1.1.1, indicates that the effective date of PRC-001-1 was the basis for selecting June 18, 2007. PRC-001-1 primarily addresses new protective systems and changes (R3 & R5) and coordination with neighboring GOP, TOP and BA entities (R4). We suggest changing the wording of Part 1.1.1 to the following: "Within 36 calendar months after the effective date of this standard, if no valid Protection System Study for that Interconnected Facility exists."

No

The 10% change is too narrow for protection system studies. Accuracies of PT, CT, wiring, and modeling all add together and therefore the threshold for a new protection system study should be 15%. a) In R2, Part 2.2, replace the term "deviation" with "change." (Note: For this calculation all that's required is to calculate percent change. ie. Webster's dictionary definition of "deviation" is 1) A variation that deviates from the standard or norm; "the deviation from the mean". 2. The difference between an observed value and the expected value of a variable or function.) b) In R2, Part 2.2, replace the term "present" with "new" and the term "most recent" with "previous". Also reflect this terminology change in the % Change equation. (the use of the terms "present" and "most recent" can be perceived to be the same.) c) It is also recommended that "V" for value be replaced by "I" for current. d) In R2, Part 2.1, please add "new", delete "present" and add either "under normal conditions" or "maximum system conditions" so that it states "Perform a new short circuit study to determine the fault current values under normal conditions, not less than once every 24 months."

No

a) Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout this standard already address notification requirements. b) In R3, Part 3.3.1, change Requirement to read: "Changes are made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities." (The current wording implies that all findings are due to errors. The reference to errors should be removed and the

emphasis of this Requirement needs to be placed on “changes” made to Protection Systems when it becomes apparent that a change is required which impacts coordination of relays.)

Yes

No

There may be instances where extenuating circumstances delay agreement beyond 90 days. For long lead time or complex protection scheme projects requiring more interaction between protective relaying engineers, exceeding the 90 day period could be acceptable to the entities involved. Evidence of mutual agreement on an extension beyond 90 days should be acceptable.

No

We recommend a consistent set of VSL timeframes across all requirements. The 10 day limits are unreasonable and, as stated in the R1.1.1 rationale, this urgency is not warranted. Most entities will have numerous Interconnection Facilities, so applying these VSLs to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general: • Lower VSL should be 60 days late. • Moderate VSL should be more than 60 days, less than a year. • High VSL should be more than a year but done. • Severe VSL should be more than a year and not done.

a) Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1, Part 1.1.2 reads - “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.” For Requirement R1, Part 1.1.2, we recommend omitting the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”. b) The standard uses different formats for identifying deadlines. Sometimes “days” are used and sometime “months” are used. It is suggested that a common format be used. c) Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime. d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2, we recommend changing to read: “Within 90 calendar days after the completion of the Protection System Study: Provide, to each affected Interconnected Facility owner, a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions).” e) There is a concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process. i) The overall process would be less burdensome by changing R2, Part 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3. ii) The overall process would be less burdensome by deleting R3, Part 3.3 because such Protection System changes are already captured by R3, Parts 3.1 and 3.2. iii) Omitting ‘project schedule’ from R3 would streamline data exchange. f) Delete ‘operating’ from the Interconnected Facilities definition because “different functional or corporate entities” sufficiently captures all of them. We also suggest defining the singular Interconnection Facility, rather than the plural.

Group

GP Strategies

Mary Jo Cooper
Yes
Yes
We agree that there should be a process for ensuring that the industry continuously evaluates the system and ensures that the relay settings are coordinated and adjusted to meet the dynamically changing grid. However, we disagree that the studies should be conducted by the owners of the facilities. We feel these studies should be conducted by the Transmission Planner or Planning Authority and the cost of the studies should be allocated equally to all users of the grid. Currently, a study is performed when a new facility is added or an existing facility is modified. Typically, the study is conducted by the Transmission Planner as identified in FAC-002 and paid for by the facility that is being modified or is being added. It makes sense that these facilities pay for the studies as they are the ones modifying the overall grid and benefit from the modification. In this case the cost should not be borne by an existing facility. The drafting team states that an owner should perform a study when the fault current changes by 10% or greater at their Interconnected Facility. The team may not have taken into account the potential that these changes are not related to that particular facility but rather from a change in the overall dynamics of the grid. For example, an influx of renewable resources (both behind and in front of the meters), retirement of generation, changes to transmission, or changes in load pockets. In addition, it excludes any new facilities added since 2007 from sharing the cost of changes to the grid. The cost for studies conducted for changes to the existing grid should be allocated to all interconnected facilities and should be performed by the Transmission Planner. As defined in the Rules of Procedure, section 500, the Transmission Planner is "the entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the PA area." The Planning Authority is the entity that maintains the information required for the studies and is the entity that could perform the studies at the lowest cost. The cost for performing the studies should be allocated to all entities doing business on the grid and the cost should be reviewed in a rate case and allocated appropriately. MOD-010 and MOD-012 already provides a requirement to provide the characteristics for system studies to the RRO for updating the models that would be used to conduct the studies. These Standards, however, have a gap in that they do not include Distribution Provider as indicated in the proposed PRC-027 Standard. We recommend the drafting team revise MOD-010 and MOD-012 to retrieve all necessary information to update the RRO model and that the Transmission Planner be tasked with performing the necessary studies.
Yes
Yes
Individual
Laura Lee
Duke Energy
Yes
No
Yes
However R1 is confusing by having two sub-requirements R1.1 and R1.2, two measures M1 and M2, and VSLs consisting of various combinations of non-compliance with sub-requirements. We think it could be made clearer by separating R1.2 out as a separate requirement with its own measure and

VSLs. We have made a similar comment on Question 8 that other requirements, measures and VSLs in this standard could be made clearer by breaking them apart. Also, Requirement R1.2 states "each affected Interconnected Facility owner" without describing how the owner may be affected.

Yes

However it's unclear what Fault duty is being referred to. Is it the total Fault current at the bus, or Fault current that flows down the line or to the generator? It should also be clarified that Fault duty is the normal case (i.e. with all sources and all lines in-service).

No

Revise second bullet under R3.1 as follows: "Changes to line impedance". Add another bullet under R3.1 as follows: "Changes to breaker failure scheme operating times". Also, we don't agree with the R3.1 Rationale that specifying a single time frame is inappropriate. A time frame similar to R3.2 should be specified. We suggest the following revised lead-in paragraph to R3.1: "According to an agreed-upon schedule or absent such an agreement, 180 calendar days prior to implementing any change or additions listed below; either at an Interconnected Facility or at other facilities when the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities".

Yes

We support the necessity for agreement, but there can be differences in philosophies that make reaching agreement difficult. How are disagreements to be handled? As the requirement is currently worded, the entity receiving the study has no alternative but to agree within the specified timeframes.

Yes

No

The requirements in this standard do not have solely one activity. Also, requirements R1, R2, and R4 do not have an activity or goal stated (other than is stated in the subparts). The requirements in this standard all have sub-requirements, multiple measures and VSLs consisting of various combinations of non-compliance with sub-requirements. We think the standard could be made clearer by separating sub-requirements out as separate requirements with their own measure and VSLs.

The order of the Requirements in PRC-027-1 should be put in chronological order to align with the Example Process outlined on page 22. PRC-001-1: It's not clear that balloting for Project 2007-06 also includes PRC-001-3. General comment - The vague language of R1 does not make it practicable for the responsible entities to implement the requirement. The Purpose is limited to coordination/relationship with the applicable entities. The Purpose is vague as to whether it applies to the Bulk Electric System. Requirement R1 does not clearly state a reliability outcome/benefit. It is not aimed to achieve one objective. The phrase "shall be familiar with the purpose and limitations of protection system schemes," is vague and not measurable. What does it mean to be "familiar" with in this context? Could this requirement be stated in a way that is measurable? The outcome is not obvious because of vague terminology. What will be the outcome of entities being "familiar purpose and limitations of protection system schemes?" The term "familiar" is too general to address a single activity. Although it can be inferred that familiarity with the purpose and limitations helps ensure reliability, what single reliability goal will be accomplished? There is no measure specified for R1 (according to the Model: each requirement must have one or more associate measures used to objectively evaluate compliance with the requirement). What type of evidence could be used so the entities are compliant with the requirement? The Data Retention language mirrors the recommended default language. However, because there are no measures, which are "used as a guide in identifying which responsible entity must keep the evidence and for how long," where do the "3 years" come from? There is no supporting document or reference to a supporting document for justification of VRFs for PRC-001-3; although, there is one for PRC-027-1 (which does not mention PRC-001-3). No explanation is given for the "High" or "Severe" VRF for R1. Generally, how is the VSL said to be "Severe" if there are no measures for R1? Effective Date – There needs to be an explanation for the time lapse of more than 3 months between approval date and the effective date of the standard. Additional clarity is needed regarding performance requirements and how an entity would demonstrate compliance with R1. Requirement R1 doesn't support the Purpose statement of the standard.

Group

Western Area Power Administration
Brandy A. Dunn
No
Don't necessarily agree with the statement: "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated.
No
No
No
We have concerns over what NERC considers to be a "Protection System Study". Needs to be defined more clearly.
No
What are the details to be provided? Should only be for significant changes.
No
See general comments below (#9).
General: Western disagrees with NERC standards becoming too specific on technical issues such as protective relay coordination. Protection Engineers are highly skilled and trained in system coordination and should be left to determine the proper course of action without the hindrance of PRC-027-1 requirements. There is a reason why, historically, protection system coordination has been termed "the Art and Science of Protective Relaying." The proposed standard also mentions that "Protection Systems remove from service only those Elements required to isolate Faults..." This statement can be problematic since backup functions such as remote Zone 3 distance elements cannot be overlapped reliably yet are necessary for N-2 and beyond contingencies. Also, in some case it may be desirable to allow for intentional overlap or mis-coordination depending on the circumstances. These issues need to be resolved in the proposed standard or the standard eliminated. Specific issues: - We have concerns over what NERC considers to be a "Protection System Study". Needs clearer definition. - Swap requirement positions R1 and R3. I.e. make R1 be R3 and R3 be R1. - R2.2: Provide equation. And, use "I" instead of "V" when referring to current. - R2.2: What values are being referred to for deviation calculation? (i.e. ground current, phase current, positive sequence, etc.) - R2.2: Clarify the fault current contribution or provide a table specifying the details - R3.1: Last bullet, suggest making the statement "Replacement of the transformer(s)" to cover all transformers. - R3.2: How does the neighboring entity know when to request? - R3: What are the details to be provided? Should only be for significant changes. - Concerned about dates and timelines associated with this standard. Often schedules and tasks change during design, checkout and commissioning. R1.1.3 and R3 need to be clarified. Western feels that this standard will create more questions than it answers. The standard, as written, is not clear or concise and would surely lead to CAN's and FAQ's.
Individual
Jack Stamper
Clark Public Utilities
Yes
No
Yes
Yes

Yes
No
The proposed Requirement R4 is not an acceptable method of confirming agreement among parties. Requirement 4.1 requires an entity to agree with the proposed changes within 90 calendar days. What if the entity thinks the proposed changes are wrong? Other standards that require entity A to provide information to entity B provide that entity B will provide written comments to entity A within a specified period of time. 4.1 should state the following: "Within 90 calendar days after receipt, provide written comments (if any) regarding the summary results of a Protection System Study, as described in Requirement R1, Part 1.2." Requirement 4.2 will require an entity needing to implement a planned change to delay the in-service date until affected entities agree with the proposal. This sets up a potential stand-off with no method of resolution. In other standards where parties provide comments the entity is required to respond to those comments within a specified period of time. However, 4.2 as worded would stop the implementation until the other parties all agree. The owner of the facility needs to have ultimate and sole control for implementing these changes and the current 4.2 would stop a project dead in its tracks until the other parties all agreed. Proceeding without this agreement would result in a standard violation and imparts power upon entities over facilities they do not own. 4.2 should state the following: "Within 30 calendar days after receipt of any written comments received per Requirement 4.1 and prior to the in-service date of any planned change at the Interconnected Facility, respond to such written comments."
Yes
Yes
Group
Associated Electric Cooperative, Inc., JRO00088
David Dockery
No
See comments posted by SERC PCS
No
Yes
AECI objects with the line of questioning here, because it does not fully address all aspects of Requirement R1. While AECI appreciates the 36 month time-frame, we did receive internal comment back from our planning engineers Relay Operations Sub-Committee: 1) Concerning our Regional Entity's Short Circuit Data Working Group, the current status is such that a unilateral AECI SC study would be technically difficult. 2) Further, significant modeling development will be necessary in order for entities to comply with this requirement through a regional study formation, ie 3 yrs is a definite push on the timeline on the Initial pass. 3) Finally, the information to be reported from a Protection System Study R1.1, and particularly the information to be communicated to other entities R1.2, may be too vague. This primary concern is for personnel being inundated by the sheer volume of data that can now be performed in relation to such studies. AECI would appreciate the SDT providing further Industry Guidance as to what would constitute a clear and concise set of information, to be transmitted or received from corresponding parties.
Yes
A 10% threshold seems simple, but the SDT may or may not wish to clarify the formula to be applied because any of the following is a valid interpretation: 1) $\text{abs}(V_{scs} - V_{pss})/V_{scs}$, 2) $\text{abs}(V_{scs} - V_{pss})/V_{pss}$, 3) $\text{abs}(V_{scs} - V_{pss})/0.5(V_{scs} + V_{pss})$, 4) $\text{abs}(V_{scs} - V_{pss})/\text{Max}(V_{scs}, V_{pss})$, or 5) $\text{abs}(V_{scs} - V_{pss})/\text{Min}(V_{scs}, V_{pss})$. Also see SERC PCS Comments.
No
AECI believes the industry would be better served by placing this list of items into a Guidance

document, and rephrasing R3 to include only "field-changes known to modify the conditions used in coordination settings of Protection Systems." Although some of the listed items are direct-impact, as currently drafted, any field-equipment changes are potentially in scope, regardless of proximity to the Interconnected Facility(s) of interest. With exception of R3.1 Bullet #1, the R2.3 10% is a better metric and the other Guidance bullets and wording we proposed above, should be added into R2.3.

No

PRC-027-1 R4.2 change: Replace: "that Protection Systems(s) changes" With: "each related Protection Systems(s) change" Rationale: AECl sympathizes with the need for agreement, and believes that to be the necessary goal. However, this requirement indicates all-or-none for notified Protection System Change(s). Entities may agree on most all communicated changes, and yet a more complicated change, particularly outside of Zone 1, may require some interim compromise, or that one particular (backward-looking) be excluded until agreement is reached. Full agreement, prior to placing facilities into service, might otherwise become a method for forcing a poor compromise on protective settings.

Yes

These facilities take time and budget to build or implement, and so 3-months prior to field-changes seems reasonable.

No

See SERC PCS Comments.

See SERC Comments Also pertaining to PRC-027-1 Page 2, Terms: , "Interconnected Facilities" definition, proposed change: Replace: "functional, operating, or corporate entities" With: "functional or operating entities" Rationale: In certain cases, independent Corporate entity is irrelevant to the planning and operations of these systems. As written, the underlying 6 G&Ts of AECl's JRO could technically and unnecessarily be subjected to this standard for AECl's internal facilities, and not just Interconnected Facilities between AECl and other non-JRO entities, although AECl's JROs functionally coordinate relay settings much as a large IOU's regional departments would.

Group

ACES Power Marketing Standards Collaborators

Jason Marshall

No

Please strike "while meeting the system performance specified within requirements established in other approved NERC reliability standards." It provides no additional explanation for the purpose and these "other approved NERC reliability standards" apply regardless of this standard. In generally, it is not necessary to reference other NERC standards within a standard and, in fact, should be avoided as a standard should stand alone.

Yes

No

(1) Conceptually, we agree with the intent of the standard and this requirement as it is presented in the application guidelines. However, more refinement is needed to make this requirement implement what is explained in the application guidelines. For instance, nowhere in Requirement R1 is it stated clearly that the responsible entity is only responsible for performing Protection System Studies (PSS) for only those breakers it owns and are protecting the Interconnection Facility. This is pretty clear in the application guidelines. (2) While we do not disagree with the time frame, we question if it should be part of the requirement. It makes more sense to include the time frame for initial compliance of a requirement in the implementation plan. In that way, the initial compliance time frame does not persist in the standard long after it is no longer needed. It is common to utilize the implementation plan to describe initial compliance dates. Furthermore, FERC approves implementation plans as part of the standards package so there is no issue with whether the implementation plan are enforceable. (3) We disagree with limiting PSS that can meet this requirement to only those that occurred after June 18, 2007 as defined in Part 1.1.1. While NERC cannot compel evidence from a date before the standards became enforceable, there is no reason that a TO, GO, or DP could not choose to utilize a PSS from before this date as evidence. (4) We think the use of PSS in Part. 1.1 is partly redundant to the definition. The definition indicates PSS is a study that demonstrates Protection Systems operate in desired sequence for clearing Faults. Part 1.1 states that the TO, GO, and DP shall perform the PSS

“to verify Protection Systems remove from service only those Elements required to isolate Faults” are removed from service. Isn’t the statement in Part 1.1 “to verify Protection Systems remove from service only those Elements required to isolate Faults” equivalent to the demonstrating that Protection Systems operate in the desired sequence for clearing faults as defined in the PSS? (5) We disagree with including the Distribution Provider in this requirement. The primary reason that a Distribution Provider owns Protection Systems that protect Interconnected Facilities is that it is often cheaper to install a fault interrupting device and its associated Protection Systems on the distribution side. These Protection Systems are typically installed per the Transmission Owner facility connection requirements which are established per FAC-001. The Transmission Owner usually still performs the PSS and short circuit study and the Distribution Provider uses settings specified by the Transmission Owner. The fact that FAC-001 applies only to the TO and allows the TO establish such facility connection requirements that applies to the DP further supports this claim. (6) The definition of Interconnection Facility is confusing and needs further refinement. First, we are not sure what the purpose of including “that are electrically joined by one or more Element(s)” is. If it is not electrically joined, it cannot be a Facility. It would not be part of the BES which is a basic requirement of the Facility definition. Second, it is not clear if this is intended to cover only jointly owned Facilities or not. We do not think that is the intention but the clause “are owned by different functional, operating or corporate entities” cause this confuses. Third, ownership cannot be defined by functional or operating entities. A corporate entity may be registered as a TO and GO. Which part of the definition applies for the interconnection between the transmission system and generator: Functional Entities or Corporate Entities? Furthermore, a functional entity or operating entity does not really describe a legal entity capable of ownership. The definition of Interconnected Facility should be a Facility that ties together two different sets of Facilities together where the Protection System coordination would be performed by different companies. This would appear to be consistent with the explanation of the standards in the application guidelines. For example, a Facility connecting two different TO transmission systems together where the TOs are owned by separate corporate entities would be an Interconnected Facility. A generation interconnection Facility would only be considered an Interconnection Facility if the GO and TO were separate corporate entities. If they were the same corporate entity, coordination would already occur and the generation interconnection Facility should not be considered an Interconnected Facility.

No

(1) While we do not have an issue with the +/- 10% Fault current threshold, we question if the TO should be responsible for calculating the percent deviation for all Protection Systems for all Interconnected Facilities. Rather the TO should be responsible for calculating Fault currents on its transmission system and should be required to calculate the percent deviation for only those breakers and associated Protection Systems it owns and are protecting an Interconnected Facility and that it has performed the Protection System Study (PSS). The TO should communicate the Fault current to the owners of other Protection Systems protecting the Interconnected Facilities for them to calculate the percent deviation. (2) The main part of the requirement needs to be modified to further clarify for which Interconnected Facilities the TO is conducting short studies. As it is written now, each TO has to perform these short circuit studies for each Interconnected Facility. This literally means a TO has to perform short circuit studies for Interconnected Facilities for which it has no information or is even remotely responsible. For example, a literal reading would mean a TO in the Eastern Interconnection would have to perform a short circuit study for an Interconnected Facility in the Western Interconnection. Obviously, this is not the drafting team’s intention but the language does need refinement.

No

(1) In general, we are supportive of the list and requirement because it helps to clarify what changes are intended in Part 1.1.3 in Requirement R1. However, we have identified two specific issues with the list. First, we question if this requirement is at least partly duplicative with FAC-001-0 R2.1.2 which requires the TO to have procedures for notification of new or modified equipment. Second, the third bullet regarding additions, removals, and replacements of transmission system Elements is too broad. This literally means that if a TO replaces a bus section with similar equipment, this requirement to notify of changes is triggered which then triggers a Protection System Study or documentation that one is not required per Requirement R1 Part 1.1.3. Ultimately, we believe the changes that need to be identified are those that actually affect the Protection Systems for the Interconnected Facilities or those that change the Fault current on the Interconnected Facilities. (2)

The 30 day requirement should be struck from Part 3.2. If a schedule is not identified by any party, it must not be pressing and an artificial deadline should not be created. (3) The language of the main requirement needs to be further refined. A literal reading would require the TO, GO, and DP to provide details about Interconnected Facilities that they neither own nor operate or to which they are even connected. Obviously, the literal meaning is not intended. The requirement needs to be refined to clarify that the TO, GO, and DP only need to provide the details for Facilities they own. (4) For Part 3.3.2, we suggest clarifying that this requirement does not apply if the equipment is replaced with like equipment and settings. We also suggest that that some sort of exemption is written into this part for extreme weather events that allows more time for notifications.

Yes

Yes, we agree. The application guidelines were particularly helpful in explaining how the Requirements R3 and R4 work together.

No

We assume this question refers to Part 4.1. While we do not see any issues with the 90 day requirement, Part 4.1 needs to be modified to reflect what a responsible entity must do if they do not agree. As written any other response than agreement is a violation. Thus, if a TO indicates it disagrees with the results of the Protection System Study (PSS) within 90 days, it technically is in violation of the requirement. The application guidelines explain that absent agreement the revisions should be proposed. We agree with this approach but the requirement simply does not say this. It should.

No

(1) The time horizon for R2 should only be Long-term Planning. The study has to be completed every 24 months and while notification in Part 2.3 has to occur within 30 days it is only after that the study to satisfy the 24 month time period is complete. (2) Requirement R3 should include Long-term Planning. Transmission system expansions would be covered under Part 3.1. (3) The VSLs for Requirement R1 are gradated based on the number of days late the requirement is met for Part 1.1 but not Part 1.2. It seems Part 1.2 should have similar gradated VSLs. (4) For Requirement R4, we suggest the VSL for Part 4.2 should clearly state that any changes made during extreme operating circumstances (i.e. extreme weather) are excluded. This is essentially a question on what is meant by "planned". Are changes made to restore service in a hurricane or tornado damaged area a few days after the devastation planned? We think they are not but see how auditors could view the changes as planned particular if any level of study was required.

(1) Please restate section 4.2. It states that it applies to Protection Systems installed at Interconnected Facilities. "Installed at" is not really the intention. It should be Protection Systems installed to protect Interconnected Facilities. While they most likely would be at the Facility, they do not have to be. For example, a 500 kV transmission line is a Facility. Protection Systems will not be "Installed at" the line but rather at the substations. (2) If PRC-001-3 R1 is going to be retained, it needs to be further refined. First, it inappropriately uses the term area when referring to a GOP. While the BA and TOP do have Balancing Authority Areas and Transmission Operator Areas, no equivalent exists with the GOP. The GOP simply operates generating units not areas. Second, the requirement confuses the role of the GO and GOP. In the functional model, it is the GO that is responsible for installing, setting and coordinating generation protection systems not the GOP. Thus, it is not clear what role the drafting team envisions for the GOP being familiar" with the purpose and limitation of protection system schemes applied in its area". Third, the requirement is written too broadly for the BA. Because the requirement compels the BA to be familiar "with the purpose and limitation of protection system schemes applied in its area" this could literally require the BA to understand many protection schemes for which it has no direct or even indirect responsibility. For instance, distance and differential protection schemes are contained within the metered boundaries of a BA Area. This requirement would compel the BA to be familiar with them even though this knowledge would have zero impact on its decision making or responsibilities. This does not align with the responsibilities assigned to the BA in the functional model. The BA being included in this requirement is likely a vestige of the version 0 standards and should be corrected. When version 0 standards were translated from the policies, BA and TOP were simply substituted for control area regardless of the role the control area was playing in the requirement. (3) The NERC function model defines one role of the Transmission Planner as "define system protection and control needs". Should the Transmission Planner have a role in this standard? For instance, should the TP actually perform the short circuit studies? (4) The application guidelines and examples are very helpful in understanding the intent of

the drafting team. However, we recommend revising the example regarding Figure 3. It would appear to assume a distribution level generator is part of the BES and subject to NERC standards. While it is possible for a generator on the distribution system to be part of the BES (i.e. if it is a Blackstart Resource), inclusion of such a generator would be unusual and an exception to the normal BES 100 kV threshold. If the generator is not part of the BES, there would be no Generation Owner registered to perform the coordination. Industry is likely to be sensitive to such an example. Removing the generator will still allow the example to communicate that a breaker and associated Protection System on the high side (100 kV or higher) of a distribution or step-down transformer would still have to be coordinated.

Individual

Eric Salsbury

Consumers Energy

We feel that this is a very difficult standard to interpret consistently as written. We think a negative vote is warranted since it is confusing and unclear for our situation. Following are specific comments to support our negative vote. In regard to the Process Flow Chart on page 21 - We assume this Process Flow Chart is intended as an illustrative clarification of the standard, not a supplement to the wording. The chart claims to be a "complete representation of the process" and as such should match identically or it should be eliminated as it causes confusion. It is our interpretation that the chart does not match the standard's wording. One example if you start with an R3 emergency replacement you end up with two conflicting results. Under 4.3.2 you have 30 days to confirm that the changes are acceptable. Under 1.1.3 you have to do a protection study so you are given 90 days per section 1.2. This entire chart should be verified to ensure that it matches the written standard and does not result in conflicting requirements. We suggest adding the sub-requirement labels to each flow chart item for easier reference to that section of the standard. In regard to Figure 3 on page 25 - The figure appears to represent the connection of a large NERC qualified generator. Does this figure also apply to a looped source distribution system or should that follow figure 4? We would like to see a definitive example that clarifies what to do for the situation where you have a looped source distribution system. In regard to Figure 4 on page 26 - the figure implies that A & B can be set to overtrip C (as no study is required) which would interrupt the BES for distribution faults. This appears to be contrary to what is intended by this standard.

Individual

Brian J Murphy

NextEra Energy Inc

Yes

No

While 36 months is allowed for studying all interconnections, what time is allowed for mitigation of identified setting or hardware change? If an issue is discovered, then an additional 12-24 months mitigation time should be allowed.

No

It would seem that NERC Standards efforts, such as PRC-027 should focus on areas that have a record of poor performance and a contributor to misoperations. The area of tie line protection addressed in PRC-027 is not an area of poor performance, see page 4 of the attachment "....Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard

PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations". Areas that are less problematic should be addressed by NERC with less intrusive methods such as Industry Alerts, general cautionary statements or a standard with less detailed documentation requirements. Thus, PRC-027, as drafted, will unnecessarily require additional focus and resources be placed in an area that has not been a problem for the reliability of the BES. Alternatively, PRC-027 should be drafted much less prescriptively from a technical standpoint, and allow for more discretion on how to conduct the study and how to coordinate the results. The prescriptive nature of many of the technical requirements PRC-027 is so narrow that it may counterproductive. A results-based approach here should focus more on conduct a study and coordinating the results, rather than dictating how the technical requirements of how study is to be completed.

Individual

Darryl Curtis

Oncor Electric Delivery Company LLC

No

Oncor takes the position that the word "only" in the Purpose is too subjective and allows for multiple interpretations. Oncor believes that in order to provide clarity, Oncor suggest that the Purpose be modified as follows: "To coordinate Protection Systems for Interconnected Facilities, such that those Protection Systems remove from service those Elements required to isolate Faults, while meeting the system performance specified within requirements established in other approved NERC Reliability Standards.

No

No

Given the "agreement" requirements defined in Requirement R4 and the uncertainty of its interpretation, many of the recent protection system studies may have to be performed again. Therefore, a more appropriate timeframe would be 5 years to have all applicable Protection System Studies completed.

Yes

Oncor takes the position that the 10% fault current threshold criteria is the only criteria needed;

Yes

No

Oncor believes agreements must be reached; however, there needs to be some definitions in the Standard to define the exact meaning of the term "agreement". In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There is sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt.

Yes

No

Until 'agreement' definitions or further clarity as to what is an "agreement", can be added the Standard, Oncor does not believe that VRFs and VSLs can be established for this standard.

Based on a thorough review of the proposed Standard, Oncor has identified several questions or

comments which need to be addressed in the Standard to ensure the Requirements are clear. • R4.1: please provide clarification of which entity would be out of compliance if the 90 day requirement is not met - initiating entity or receiving entity or both • M9: What does "confirmation" mean as explained in Measure M9? • R4: please incorporate a definition of "agreement" • R4.2: please incorporate some examples for "evidence of agreement"? o There are two types of agreement that are needed; the first being an "agreement" with the overall projected relaying scheme (i.e. agreement with preliminary conceptual design detailing proposed protection scheme changes). This is prior to any equipment being purchased. The second agreement, which could be identified as more of a concurrence, is agreement that both relay systems coordinate from a protection standpoint (i.e. concurrence with relay setting changes). The relay setting process and concurrences occur later in the project closer to the in-service dates. In addition, the sub requirements 4.3.1 and 4.3.2 calls for confirmation of the Protection System changes are acceptable pursuant to notification received in Requirement 3, within 30 days, however the sub requirements provide no mechanism for resolution in the event the changes are not acceptable to the receiving entity within 30 days of receipt. Oncor suggest that these two sub requirements be removed. There is sufficient checks and balances under 4.2 to provide coverage for any disagreement between entities without the need to self-report under the 4.3.1 and 4.3.2 if an agreement cannot be reached within 30 days of receipt. • R3.1: please provide further clarification of the statement "modifies the conditions used". It would seem that most system changes would modify the conditions used even though for many of those changes, coordination would not be impacted. Oncor takes the position that the phrase provides ambiguity and subjectivity that would difficult to measure or audit.

Individual

RoLynda Shumpert

South Carolina Electric and Gas

Yes

No

Yes

Yes

No

R3.3 in its entirety should be removed considering that all conditions covered by R3.3 are already covered by R3.1 which states: "New installation, replacement with different types, or modification of: protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios" If a correction or replacement of a protection system element is made per R3.3, this is the same thing as a modification covered under R3.1. It is noted that R4 would need to be reworded to accommodate unplanned and emergency protection system changes.

Yes

Yes

R4.1 only mentions R1. R4.2 should be reworded to make it clear that entities have 90 days to respond to proposed protection system changes received per R3.1. The concern is that with no specified time the responding entity can delay the initiating entity's schedule even if the protection system changes were shared well in advance of the in service date.

Yes

Group

Kansas City Power & Light

Tim Hinken

No

The reliability objective of this standard should be to insure that there is an agreement between two interconnected entities of relay protection schemes and relay protection settings for the interconnected facilities. This is achieved if there is documentation stating that the Interconnected operating companies have reached agreement on protection schemes and protective relay settings. This standard should only require documentation that neighboring owners are talking and agreeing with one another in relation to protection and control. The present purpose makes it appear that you are in violation of the standard any time the system has a misoperation because of relay setting regardless of whether both parties have agreed on the settings used but the measures tend to measure agreement with the other entity. This is the reason that the present purpose needs to be rewritten the auditors may interpret the purpose to indicate any misoperation due to setting issues is a violation.

No

The applicability should also include Transmission Operators and Generator Operators as it is possible for jointly held facilities to be owned by several parties and operated by another party and relay protection responsibilities could be with the Operator of the facility. It should be clarified the proposed Standard is applicable to Distribution Providers that provide protection for BES Elements.

No

The protective systems were coordinated when installed. If the power system has not undergone any significant change, then line impedances and fault current levels are the same and the original settings are still valid. So, no new study is required based on the passage of time. A new study is needed only if there have been significant system changes as outlined under question 5 and requirement R3. Requirement 1.1 states each entity must perform a system protection coordination study, however, the coordination efforts will be joint efforts between the entities and sharing of pertinent information such that an effective study can be performed. The proposed Standard should make it clear the study effort can be a joint study between the entities involved and that independent studies are not necessarily intended by each entity.

No

Primary protection of most transmission lines is impedance based. Sensitive ground over current systems are used for communications assisted tripping and time ground over current systems are typically used as backup protection. Some line protection is differential based. Some entities also apply instantaneous ground over current relaying for faults at some fraction of the protected line. Increases in fault current do not affect impedance based relaying. Communications assisted sensitive ground elements are set well below available fault current levels and increases in fault current levels will not hinder proper operation. Differential based systems would also not be harmed by fault current increases unless fault currents increase enough to result in ct saturation. Since time ground over current relays are usually used as backup protection they are typically set only to operate if the primary relaying protection has failed. These relays are typically set to coordinate based on time delays for ground faults on the protected line. Because the overcurrent curves are based on a log scale the increase in current magnitude does not correlate to the same percentage in time. Instantaneous ground over current elements are most susceptible to misoperations caused by increases in fault current, however these elements should be initially set to protect only the first 50 to 70% of the protected line based on the fault current at the remote end. With this in mind a fault current increase of 10% is not significant by itself to require a setting review and it is very difficult to see how a 10% decrease can affect the coordination unless over current elements are the primary protection elements or over currents elements can prevent the operation of the other protection functions. If the SDT is adamant about having a periodic review of fault current levels then the time should be extended to 5 years and the fault current level should be increased to 20% on the protected line.

No

Bullet item #3 is too broad. The NERC Glossary definition for Element is, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.". For example, a disconnect switch would be considered an Element, but a change of this component would not warrant a change to relay protection. Recommend modifying bullet item #3 to, "Additions, removals, or replacements of transmission system Element(s) that have an impact on relay protection systems or component(s)"

Yes
No
These can be matters of extreme complexity in design, implementation and operation. Stipulating that 90 days (Requirement 4.1) and 30 days (Requirement 4.3) is sufficient time to come to an agreement is presumptuous and is not necessary. Requirements 4.1 and 4.3 should stipulate that entities in receipt of proposed changes to relay protection system(s) or component(s) be evaluated and responded to by the entity in receipt. The response could be agreement or non-agreement with concerns or objections noted in the response.
No
The 10 day increments represent a 5% error and considering this is a six month requirement. The 10 day increment represents 4 – 6 working days across 2 weekends and including a holiday. Recommend the increments be increased to allow at least 10 working days which would be at least 15 calendar day increments. VSL for R2, part 2.1 – The 10 day increments represent a 1% error and considering this is a 24 month requirement. Recommend the increments be increased to 30 days to make more sense with the 24 month period.
Requirement 1.1 of R1 states, "Perform a Protection System Study for each Interconnected Facility to verify that Protection Systems remove from service only those Elements required to isolate Faults as follows:". The purpose of this standard should not be to remove from service only those Elements required to isolate Faults, therefore 1.1 above should state, "Perform a Protection System Study for each Interconnected Facility as follows:". Requirement 1.1.2 of R1 states, "Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required." Since this Requirement is an action as a result of requirement R2 and as noted in the response to question 6 above, R2 should be deleted. If the SDT is adamant about having a periodic review of fault current levels then the fault current level should be increased to 20% on the protected line. A 10% fault current change is not significant enough to require a new protection system study. Requirements R4.3 and R3.3 are actions as a result of a misoperation and because there is already a standard (PRC-004) that deals with misoperations these two requirements should not be covered in this standard if changes need to be made due to misoperations they should be made in the misoperation standard (PRC-004). This standard is not intended to replace the Misoperation Standard and any requirements addressing misoperations gives FERC, NERC and the Audit Teams the wrong impression of the intent of this standard. All Protection System Studies are dependent on accurate system models. Individual Entities should not be responsible for development and maintenance of an accurate Regional model or model to be used between Regions. Individual Entities should only be responsible for providing the information on their system to the Regional Entity so that an accurate model can be maintained by the RC. I propose that this standard be applicable to the Region and require the Region to maintain an accurate model that includes zero sequence impedance and is useful for Protection System Studies. This system model also needs to be accurate between Regions for Protection System Studies that span between Regions. This will require that the standard also be applicable to NERC RRO and require RRO to oversee the process of maintaining an accurate national model or equivalents that can be used between Regions. Anything less than this is placing an unfair burden and unrealistic expectation on the TO to produce and maintain an accurate model for interconnecting Protection System Studies. A dispute resolution mechanism also needs to be required to provide for instances where entities cannot come to a mutual agreement. Recommend a requirement be included for entities to request applicable RC(s) to arbitrate to bring resolution to a matter.
Individual
Jian Zhang
TransAlta Centralia Generation LLC
No
The Interconnected Facilities definition is not clear.
Yes
The applicability should include other functional entities which should provide power system study data.

1) Applicability 4.2 Facilities should be Protection System installed at Interconnected Facilities that required coordination. 2) R2- For the Inteconnected Facilies only for the purpose of the generator interconnection, only the Transmission Owner providing the generator interconnection should be required to perform the tasks as mentioned in R2, not the other entity (generator) even though it is registered as the Transmssion Owner. 3) R2 2.1 perform a short circuit study to determine the present fault current values, not less than once every 24 months. 24 months is too often. Suggest to change to "once every 60 months unless there is major equipment change on the system".
Individual
Pablo Oñate
El Paso Electric
Yes
No
Yes
It is unclear whether the proposed standard intends to reach 10% or greater deviations that accumulate over the course of a more extended period of time (i.e., greater than 2 years), or whether an entity can seek to perform multiple studies within a compressed period of time in such a way that it can ensure that a 10% deviation will not be reached from study to study, as illustrated below: • Study performed in Year 1 shows a 5% deviation • Study performed 12 months later (in Year 2) shows a 5% deviation • Study performed 12 months later (in Year 3) shows a 5% deviation [Cumulative deviation of 15% within 3 years, but only a 5% deviation from study to study]
Yes
Yes
No
EPE believes the timelines are not adequate when coordinating protection system studies involving sequential interdependence among parties for interconnected facilities . Timing of study data should correlate with any written agreements or procedures agreed to between the various parties. EPE also believes the documentation requirements within this draft Standard slow down the process, therefore increasing the time needed to complete and communicate the study data. The proposed Standard fails to address two important and likely types of situations: (a) the situation in which an interconnected entity fails to respond with study results or to a planned change at the Interconnected Facility, or (b) the situation in which disagreements between the entities are not resolved within the proposed Standard's time clock.

Additional Comments Received:

**Dominion Resources Services, Inc.
Mike Garton**

Question 1

In the current PRC-001-1 standard the meaning of the term “coordination” has and still is interpreted in two ways. One interpretation is viewed from the technical aspect as “relay coordination” and the second is viewed from an inter-communication aspect as “coordination of information” between entities. The term “coordination” should be removed from the new standard Title and Purpose. Recommend changing **Title** to: “Protection System Interconnected Facility Performance During Faults”. Also, recommended is to change the **Purpose** to read: “To communicate and exchange Protection System Studies for Interconnected Facilities such that the Protection Systems can be properly coordinated to remove from service only those Elements required to isolate Faults.” In PRC- 027-1, use the term coordination only when referring to the technical aspects of the relay coordination within a Requirement when applicable.

Under **Purpose**, delete: “while meeting the system performance specified within requirements established in other approved NERC Reliability Standards” as it is superfluous and could cause duplicative or conflicting work. The Purpose without this clause is clear, concise, and consistent with rest of the 1st draft of this standard. The resulting coordinated Protection System must meet ‘the system performance specified within requirements established in other approved NERC Reliability Standards’ and is addressed when the entity complies with those standards. A Compliance Enforcement Entity (CEA) could interpret this clause to require the entity to repeat such work in a Protection System Study within PRC-027-1.

Question 4

- a). In R2-2.2 Replace the term “deviation” with “change”. {(Note: For this calculation all that is required is to calculate percent change. i.e. Webster’s dictionary definition of “deviation” is 1) A variation that deviates from the standard or norm; “the deviation from the mean”. 2. The difference between an observed value and the expected value of a variable or function. This is not a statistical calculation.) }
- b). In R2-2.2, Replace the term “present” with “new” and the term “most recent” with “previous”.
- c). Change the % Deviation Equation to % Change. Reflect as stated above in the equation legend (the use of the terms “present” and “most recent” can be perceived to be the same).
- d). Replace “V” (Value) with “I” (Current) in the % Change Equation. “V” is frequently used to represent Voltage and this could lead to confusion.
- e). In M5 Replace the term “deviation” with “change”
- f). In R2-2.1 please add “new”, delete “present” and add either “under normal conditions” or “maximum system conditions” so that it

states “Perform a *new* short circuit study to determine the Fault current values *under normal conditions*, not less than once every

24 months.

Question 5 (NO)

- a). Any reference to project scheduling should be removed from this standard since time frame requirements listed throughout the draft already address notification requirements. By using the term project scheduling this implies that detailed project information needs to be included in the information exchange. The standard should not dictate the information exchange details required and should allow the entities to determine what information is required in the exchange in order to achieve protection coordination in the appropriate timeframe.
- b). In R3 reword to read: “Each Functional Entity shall provide to other Functional Entities connected to an Interconnected Facility, the details of the Protection System as follows:” (It is not necessary to include (e.g. Examples) since references to these are already listed in R3-3.1.)
- c). In R3-3.1 reword to read: “When adding new or modifying existing Interconnected Facilities or when making changes to other facilities where the proposed change modifies the conditions used in the coordination of Protection Systems of the Interconnected Facilities”
- d). Bullets: 1st bullet -Recommend changing reference to “protective Function settings” to “protection settings” / 2nd bullet – Reword to read: “Line impedance changes” / 3rd bullet – Remove the word “system”
- e). In R3-3.3.1 change Requirement to read: “Changes found during Misoperation, commissioning, or maintenance activities

that modify the conditions used in the coordination of Protection Systems. “

Question 7

Reword R4., 4.3 to read: “Within 30 calendar days after receiving notification of:”

Question 8 (NO)

- a). Dominion recommends a consistent set of VSL timeframes across all requirements. The 10 day limits are too tight and as stated in the R1.1.1 rationale this urgency is not warranted. Most entities will have numerous Interconnection Facilities so applying these VSL to each one could quickly stack up violations for being a few days tardy in the midst of this imposed heavy workload. In general:
 - Lower VSL should be 30 days late.
 - Moderate VSL should be more than 30 days, less than a year.
 - High VSL should be more than a year but done.
 - Severe VSL should be more than a year and not done.

Question 9

- a). Dominion is concerned that a YES vote will also endorse the revision, also part of this project, to PRC-001-3, would then be reduced to only one requirement that is not measurable and does not contribute to the purpose of the standard. The Measure for the requirement has also been removed. The PRC-001 standard should be retired or mapped to another standard.
- b). The proposed definition of Protection System Study is vague and introduces subjective terms such as “demonstrates” and “desired sequences”. Recommend the following definition: “A study that determines the proper selection of settings for existing or proposed protective relays in order to properly isolate Elements.”
- c). Throughout the 1st draft of this standard, there are Requirements that make reference to another Requirement. This occurs in several places (R1-1.1.2, R1-1.1.3, R2-2.2, R2-2.3, R4-4.1, R4-4.2, R4-4.3-4.3.1 and R4-4.3-4.3.2). By referring to another Requirement within a specific Requirement, it makes the overall standard difficult to follow and distracts from the objective of a specific Requirement because of having to read between two Requirements to understand the overall meaning. For example: R1-1.1.2 reads - **“Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility, as described in Requirement R2, unless the entity can demonstrate such a study is not required.”** For Requirement R1-1.1.2 - Omit the reference to R2 and reword so that the requirement is specific. Recommend changing to read: “Within 6 calendar months after determining or being notified of a 10% or greater change in Fault current for that Interconnected Facility unless the entity can demonstrate such a study is not required”.
- Change R1-1.1.3 wording to read “When proposing or being notified of a change that modifies the conditions used in the coordination of Protection Systems at the Interconnected Facility unless the entity can demonstrate such a study is not required.”
 - R2-2.2, delete reference to R2. Delete “pursuant to Requirement R2, 2.1”.
 - Change R4-4.1 to read: “Within 90 calendar days of receiving summary results of a new Protection System Study, confirm agreement with the summary results.”
 - Change R4-4.2 to read: “Prior to the installation of a proposed change that modifies the existing conditions used in the coordination of Protection Systems of the Interconnected Facilities, confirm the affected Interconnected Facility owner(s) agree with the Protection System(s) change.”
 - Change R4-4.3.1 to read: “Changes made to a Protection System as a result of findings during Misoperation investigations, commissioning, or maintenance activities, confirm the Protection System(s) changes are acceptable.”
 - Change R4-4.3.2 to read: “Emergency replacements are made due to failures of Protection System components confirm the Protection System(s) changes are acceptable.”
- d) Throughout the 1st draft of this standard, there are references to a variety of time horizons (calendar days, calendar months) and within individual Requirements where time schedules are involved, the wording of the Requirement is not consistent when calendar days or months are referenced. For example: R1-1.1-1.1.1 references the time schedule at the beginning of the Requirement whereas R1-1.2 references the time schedule at the end of the Requirement. Recommend using a standard wording format and list the time horizons in the beginning of the Requirement in all Requirements that have time requirements involved. For Requirement R1-1.2,

Change wording to read: **“Within 90 calendar days after the completion of the Protection System Study, provide to each affected Interconnected Facility owner a summary of the results of each Protection System Study performed (including at a minimum the Protection System(s) reviewed and any proposed revisions).”**

- Change R2- 2.3 wording to read: Within 30 calendar days after identifying that the calculation performed between the previous Protection System Study and the new study indicates a change in Fault current of 10% or greater, notify each Interconnected Facility owner, at which the 10% or greater change applies.
 - Chang R3-3.2 wording to read: “Within 30 calendar days of receiving a request for information in the absence of an agreed-upon schedule or according to an agreed-upon schedule with a Transmission Owner, Generator Owner, or Distribution Provider.”
- e). Throughout this 1st draft of the standard, there are references that illustrate documentation requirements that are inconsistent. Recommend all be written as “(hard copy or electronic file formats)”.
- f). Please note that there appears to be an inconsistency in the 24 month requirement of R 2.2.1 and the ongoing work in TPL-001-2 draft 5 R2 2.6.1 which allows short circuit studies to be five calendar years old. PRC-027-1 R3 will trigger a Protection System Study if there are proximate changes in the meantime.
- g). There are several requirements stipulated throughout the draft standard creating the concern with the various time requirements for studies, notification, and replying. Tracking and documentation requirements will be very burdensome. We request the drafting team consider streamlining the data required in the exchange of studies and the overall process.
- 1). The overall process would be less burdensome by changing the R2 2.1 to “not less than once every 5 calendar years” which would be consistent with TPL-001-2 draft 5 R2 2.6.1 (see comment 9c above). Our experience is that the vast majority of Protection System Studies are triggered by R3.
 - 2). The overall process would be less burdensome by deleting R3 3.3 because such Protection System changes are already captured by R3 3.1 and 3.2.
 - 3). Omitting ‘project schedule’ from R3 would streamline data exchange.
- h). There is confusion on the connections at the end of the flow chart. Please provide clarification.

END