Individual or group. (47 Responses)
Name (27 Responses)
Organization (27 Responses)
Group Name (20 Responses)
Lead Contact (20 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (47 Responses)
Question 1 (0 Responses)
Question 1 Comments (46 Responses)

Group
MRO NSRF
Russel Mountjoy
In the rationale for Requirement R1 Part 1.1.1, the SPCSDT acknowledges that "...The drafting team has no evidence there is widespread mis-coordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame." We suggest, using the same aforementioned rationale, if there is no widespread mis-coordination, then, why create a mandatory requirement. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. Per R3, The NSRF recommends to rewrite and update R3 to read: Each TO, GO and DP should provide "when requested" by each TO, GO or DP... As written if an entity misses one piece of information then there we be a required self-report. The fact of pushing information is not a Reliability issue. The applicable entity should pass information when requested to by the asking entity.
Individual
Thomas Foltz
American Electric Power
We believe the usage of the term "interconnecting bus" within figures 1 through 5 unintentionally causes confusion in identifying the Interconnecting Element. We suggest removing interconnecting bus from the illustrations, and instead, use color coding to clearly indicate the Interconnecting Element. We suggest adding a sentence at the beginning of Figure 5, similar to the other figures, which verbally describes the Interconnecting Element in that particular example.
Individual
Brenda Frazer
Edison Mission Marketing & Trading Inc.
The requirement for all our NERC sites to perform a Protection System Coordination Study will be an expensive and burdensome effort. We have funded internconnection and system impact studies already. This effort, if critical to the BES is best undertaken by the TO, who has a wider purview of the BES. This standard has the potential to include studies at all of our Wind sites, because the Transmission Owners will be required to perform studies at the interconnecting substations. In the rationale for R1 Part 1.1.1, the drafting team states, "The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame". The time frame to conclude the study is 60 months. If there is no issues now, why perform a study that is due in 5 years? What value is that? This is a poorly organized standard revision, constantly referring to requirements later in in the standard. It makes for a difficult read.
Individual
Ayesha Sabouba

Hydro One
Agree
TFSP
Individual
Silvia Parada Micthell
NextEra Energy
R3.1. Bullets 2 , 3 and 4. Concerned that these state “changes …. that alter any sequence component…”. NextEra Energy recommends this be revised to state “changes…..that significantly alter any sequence component….” The current wording would allow an auditor to ask if we even insignificant changes such as a few inches on a jumper on a 10 mile transmission line. With the work “significantly” added, TOs can define a change that triggers a review as when it would have an effect on relaying.
Group
Northeast Power Corodinating Council
Guy Zito
The Purpose statement “To coordinate Protection Systems for Interconnecting Elements such that Protection System components operate in the intended sequence during Faults” is confusing. Are the protection systems involved specifically for the Interconnecting Element, or between Facilities connected by an Interconnecting Element? It also inappropriate because the standard does not address Protection System coordination among operating entities. According to the NERC White Paper “Power Plant and Transmission System Protection Coordination”, stator ground protection may need to be coordinated with transmission system faults. Stator ground is a generator protection – so is that in scope of the PSCS specified in the standard since this protection is a generator protection, not an Interconnecting Element protection? For Part 3.1, it is not clear what is meant by “Details….. associated with the Interconnecting Element or at other Facilities…..” What is the burden of proof associated with this requirement? In the long term planning horizon, is it implied this assessment be made through short circuit studies? It would be proper to associate Part 3.1 solely with changes/additions “either at an existing or new Facility associated with the Interconnecting Element….”. Changes at other Facilities could mean 1, 2 or 3 busses away and we believe if these changes were significant, they would manifest themselves in a significant change in Fault current levels. Furthermore, in an audit, the burden of proof lies with the owner to show these changes “at other Facilities” don’t affect coordination. Suggest the following change to the wording: “Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) where such changes result in a change of 10% or greater in either single line-to-ground or three-phase fault current as defined in R2.2.” The Process Flow chart in the Applications Guidelines of the standard needs to be revised to reflect the revisions in the standard.
Group
Pepco Holdings Inc. & Affiliates
David Thorne
1) A word search of the Final Report on the August 14, 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. 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. 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. 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. 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 PHI supports the overall desire to ensure that protective systems are properly coordinated; PHI sees 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 R1.1.1 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. The above comment was also submitted with previous drafts of this standard. In previous responses the SDT stated that PRC-027 was being developed in response to FERC Order 693. However, Order 693 only directs NERC to address specific deficiencies in PRC-001 surrounding certain measures and levels of non-compliance relating to the notification and response to the detection of failures in relay protection systems. As such, PHI believes PRC-027 goes well beyond what is was directed by FERC, and the stated purpose of the SAR. PHI urges the SDT to revisit FERC Order 693 and revise this standard as appropriate to address only the stated FERC directives. 2) Based on the arguments presented in the above comments, including the lack of 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, PHI suggests that NERC conduct a Cost Effective Analysis (CEA) to provide information about cost impacts (e.g., implementation and ongoing compliance resource requirements) of this draft standard and its relative effectiveness in preventing widespread blackouts, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of this standard. 3) PHI finds that splitting Requirement R4 into two requirements (R4 & R5) does little to address the root problem associated with mandating mutual agreement, which essentially R5 requires, since any setting changes cannot be implemented until both parties agree that all identified coordination issues have been addressed. PHI suggests Requirement R5 be removed entirely or extensively re-written to address the concerns outlined below: Requirement R5 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 R5 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? 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. It is unreasonable and unfair to hold one party non-compliant due to the failure of

another party to reach agreement. Furthermore, in the example provided above, it is a detriment to reliability to delay implementation of the setting change on breaker D just because mutual agreement could not be reached. 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 a clear division of responsibilities and assignment of who will be held non-compliant if agreement cannot be reached is unfair to either party. 4) For the case where one registered entity represents multiple Functional Entities and the same protection group performs all the coordination, the drafting team included the following note: In cases where a single group performs an overall coordination study for a given Interconnecting Element; a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities. However, this reference is only included in the Rationale boxes and the Guidelines and Technical Basis sections and not in the associated Requirements and Measures. The Measures themselves for Requirements R3 and R4 are very specific that acceptable evidence must include dated documentation that the information was supplied/exchanged between Functional Entities. What constitutes acceptable evidence to satisfy R3 & R4 if a single protection group, which is responsible for all protection coordination for both TO and DP functions within the same company, performs all the coordination for both groups? Does the PSCS have to specifically mention that the PSCS was performed by a single protection group on behalf of both Functional Entities? Or, does there need to be dated evidence that some representative from each Functional Entity has reviewed the information and signed off on it? A specific clarification on this point in needed within the wording of the Measures themselves and not just in the Rationale box.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Although appreciative of the drafting team's efforts in developing PRC-027-1, LES does not believe that there will be an improvement to BES reliability that justifies the cost and effort involved in compliance with this new standard. In its response to LES' previous comments, the drafting team contended that PRC-027-1 was necessary "to codify the roles and responsibilities of the interconnecting owners to achieve coordination of Protection Systems that affect the reliability of the BES." Although LES believes PRC-001 would still be adequate for this purpose, at a minimum, the replacement for PRC-001 should be a standard that is much less prescriptive and one that, to a greater degree, acknowledges the necessity of engineering judgment than does the current draft of PRC-027. As an example, R3 requires that functional entities provide details of a proposed change to the other interconnected entities when the change modifies the conditions used in the coordination of Protection Systems. In this instance, it is obvious that some engineering judgment must be exercised in determining if a small change actually modifies the conditions used in coordination. Does the drafting team contend that this determination can be made by one entity or must there be consensus between the interconnected entities? A less prescriptive standard would avoid the compliance questions raised by a situation such as this and allow entities to continue the commonsense approach to coordination that they have taken in the past.
Group
North American Generator Forum - Standard Review Team (NAGF-SRT)
Allen Schriver
Comments: The statement was made in the 12/5/13 webinar that PRC-027-1 requires nothing more in the way of GO-TO information exchanges than what is already mandated in PRC-001, but PRC-001 requires just that TOs "coordinate" their changes with others while PRC-027-1 makes GOs perform a Protection System Coordination Study (PSCS) for TO changes or provide a technical justification as to why a PSCS is not required. The only inputs that GOs need from TOs are the fault current at interconnecting buses (affects the GO's arc-flash studies) and the grid X/R ratio, so PRC-

001 coordination for TO changes would typically consist for GOs of just obtaining these two values, not requesting and analyzing the detailed TO information cited on p.23 of PRC-027-1 (“power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings”). There remains the technical issue that TO changes do not affect GOs’ Protection System configurations or settings. That is, making GOs perform PSCSs would serve no useful purpose, especially since everything involving tripping elements in the intended sequence (the stated purpose of PRC-027-1) is in the TO’s system. GOs should consequently have no Protection System coordination duties other reporting planned changes prior to implementation and receiving the two inputs cited above, per PRC-001. The following issues and corresponding proposed solutions are offered for consideration of the SDT: 1) Issue: We believe that there exist too many time frame measurements (14) in total for this standard. The burden of tracking these time frames for each interconnection is excessively onerous. The time frames noted in the draft standard are listed here to demonstrate the extent of the problem. The time frames identified are: • 60 months post effective date of the standard, have a PSCS for each IE (R1.1.1) • 12 months post If change > 10%, have a PSCS for IE (R1.1.2) • On an agreed upon time frame (variable) – schedule, have a PSCS for IE (proposed changes) – (R1.1.3) • 6 month post notice of “other” emergency equipment change, PSCS for IE (R1.1.4) • 60 months (recurring), TO calc If (new), % change, communicate (R.2.1, R2.2) • 30 days post ID If(new) change > 10%, notify others (R2.2.1) • Before coordination change/addition, notify others (R3.1) • 30 days post request for info, provide info (R3.2) • On an agreed upon schedule (variable) post request for info, provide info (R3.2) • 30 post change (misop. Investigation, maint., emergency replacement), notify others (R3.3) • 90 days post PSCS finished, provide to others (R1.2) • 90 days post receipt of PSCS, confirm review and state of issues (R4) • On agreed upon schedule post receipt of PSCSS, confirm review and state of issues. (R4) • Before change/addition, address any R4 issues (R5) 1A) Proposed Solution: The drafting team should strive to eliminate any and all that are not absolutely necessary. Perhaps more usage of “mutually agreed upon time frames” could relieve the burden. 2) Issue - Multiple measure #’s used for each Requirement number. 2A) Proposed Solution – Either one of the following: a) separate the multiple requirements embedded within each major Requirement number so that the requirement number and measure number’s match for each requirement, or b) group the various measures listed for each main Requirement number in a single measure. Non-matching numbers for the requirements & measures is confusing. 3) Issue - R3 should state what is to be provided. 3A) Proposed Solution – Add “the following information” after “provide” in the 1st line of R3. 4) Issue - R3.1 is confusing because of the use of “either” and two instances of “or” which follow. Also, no colon introduces the bulleted text. 4A) Proposed Solution – Modify R3.1 to the following: “Details for any proposed change or addition listed below [at existing / new Facilities associated with the Interconnecting Element or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)]: 5) Issue - An auditor may argue that for the changes referenced in R3.3 an entity proposes to initiate (to change or add replacement equipment), at some instant in time has a plan and intends to make the change, and therefore is subject to R3.1 (and should have notified others prior to the change or addition). 5A) Proposed Solution – In order to prevent potential confusion, would the SDT consider modifying R4 & R5 to include exclusions for a PSCS performed as a result of “other changes” specified in R3.3. 6) Issue - R3.3 wording needs improvement. A reader is looking for what information must be provided as they goes from R3 to 3.1, 3.2, and 3.3. Beginning 3.3 with “Within 30…” makes it difficult to determine what is to be provided. 6A) Proposed Solution – Move “within 30…” to the end of the sentence so that it is immediately evident that the entity shall provide “details of permanent changes…” 7) Issue - The short circuit (R2.2.1) section of the process flow chart in the Application Guidelines section is short circuited. 7A) Proposed Solution –Remove short circuit in the diagram.
Individual
Brett Holland
Kansas City Power & Light
What makes the internal lines of a single Registered Transmission Owner any different than a Registered Entity that represents multiple functional entity responsibilities, i.e. Generator Owner, Transmission Owner, and Distribution Provider, where one single group performs the overall coordination study? We propose the following change under the Definitions of Terms Used in

Standard - Interconnecting Element part b) should be changed to read: b) owned by the same Registered Entity that represents multiple functional entity responsibilities (Transmission Owner, Generator Owner, or Distribution Provider) where no one single group performs the overall coordination study for the given Interconnecting Element. This change to the standard does not affect the purpose of the standard, which is to provide coordination. Our proposed change clarifies that where one single System Protection group is performing the coordination that is required, then the communication will take place within the System Protection group and will be accomplished exactly the same way as it would be for internal lines of a single Registered Transmission Owner. - NEXT – We completely agree with the purpose of the standard; to coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in the intended sequence during faults. We believe that the standard needs to take into account the differences between Owners that use communication assisted schemes and those that do not. We believe that the 60 month fault study requirement should not be required for utilities that do not use instantaneous overcurrents or time overcurrents that are always slower than zone 2 time. We propose the following change to R2; R2. For each Interconnecting Element on its System, the Transmission Owner shall technically justify why Fault current does not affect the Protection Coordination, or once every 60 months: If you should choose to accept our proposed change to R2, then the removal of the technical justifications from Requirement R2 in the Application Guidelines cannot be made. It is not true that all primary and backup protection is equal. Note the contrast in the following examples. In a scheme that employs only step distance and overcurrents, Zone 2 would be the primary trip for a fault near the remote end, and the overcurrents or Zone 3 would be the backup. In a scheme that employs communication assisted tripping the piloted scheme would be the primary trip, Zone 2 would be the backup, and the overcurrents or Zone 3 may act as the second layer of backup. The chances of needing the second layer of backup are extremely low. In a scheme that employs two forms of communication assisted schemes, one piloted scheme would be the primary trip, one piloted scheme would be the backup, Zone 2 would be the second layer of backup, and the overcurrents or Zone 3 would be the third layer of backup. The chances of needing the second or third layer of backup are extremely low. Note that during the Webinar on December 5, 2013 the statement below was made that reinforces the fact that R2 for Transmission Owners interacting with Generator Owners is unnecessary if it can be shown that system fault current does not affect the coordination provided. …. “particularly in generation sites, the majority of Fault current being contributed is coming from the generator and it is going to be rare unless you add a generator or retire a generator that the fault current evaluation done by the Transmission Owner at that bus is ever going to change by more than that 10% ……. by using a fault current trigger it may indeed be that they never have to be reviewed.” Why should a Transmission Owner be required to periodically perform a short circuit study at a generator bus when the fault contributed by the generator will never change by 10% unless a unit is retired, modified, or added? Requirement R2 specifies a 10% change in fault current as the trigger for a review of the Protection Coordination. We believe that the only time that a Protection Coordination Study should be triggered is if the fault current increases by more than 10%. Since Fault studies are conducted with all generation on, the Fault current calculated by the short circuit study will be greater than the Fault current under most conditions, because all generation is rarely on. Therefore reductions in fault current are relative and a 10% decrease could be the Fault current that the system typically operates at. We propose the following change to 2.2.1; 2.2.1 Within 30 calendar days after identification of an increase of 10% or greater in either single line to ground of 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection Systems(s) associated with the Interconnecting Element(s). Due to the reasons presented above we do not agree with the changes made in the Application Guidelines associated to Requirement R2 or the Process Flow Chart portion that map Requirement R2.
Group
Tacoma Power
Chang G. Choi
On the last page of the Implementation Plan, change “…twelve (12) months after the date that the PRC-001-3 is…” to “…twelve (12) months after the date that PRC-001-3 is…” In the proposed definition of ‘Interconnecting Element’, the verbiage “owned by the same Registered Entity that represents multiple functional entity responsibilities” poses at least two challenges. First, it seems to

suggest that any BES Element owned by that entity would be an Interconnecting Element. It is believed that this is not the intent of the definition. Consider language like one of the following instead: “owned by the same Registered Entity that represents multiple functional entity responsibilities where more than one of these functional entities are responsible for the electrically joined Facilities” or “owned by the same Registered Entity but represented by multiple functional entity responsibilities.” Second, an additional challenge for Registered Entities that represent multiple functional entity responsibilities may be identifying which Element(s) is/are the Interconnecting Element(s). For example, are transmission Facilities near generation Facilities associated with the Generator Owner function or the Transmission Owner function? Similarly, are transmission Facilities near distribution Facilities associated with the Distribution Provider function or the Transmission Owner function? In these cases, the Registered Entity should be afforded some latitude in defining the Interconnecting Element(s). For example, referring to Figure 3 in the Application Guidelines, assume that there is one owner for all of the equipment represented. Further assume that the Registered Entity considers the Protection System, installed for the purpose of detecting Faults on BES Elements, at Breaker C to be associated with its Transmission Owner function. Then, it appears that there would be no Interconnecting Element in this scenario, according to the proposed definition of an Interconnecting Element. On the other hand, assume that the Registered Entity considers the Protection System, installed for the purpose of detecting Faults on BES Elements, at Breaker C to be associated with its Distribution Provide function. Then, it appears that there would be an Interconnecting Element in this scenario, according to the proposed definition of an Interconnecting Element. It might help to have one or more examples in the Application Guidelines of how part (b) of the proposed definition of an Interconnecting Element would be applied. In the Purpose, remove ‘components’. It should be sufficient to simply state that the purpose is “[t]o coordinate Protection Systems for Interconnecting Elements, such that Protection Systems operate in the intended sequence during Faults.” This purpose statement is also more consistent with the proposed definition of a Protection System Coordination Study. After a PSCS for an Interconnecting Element is developed and is accepted and implemented by all applicable entities, if a mis-operation associated with the Interconnecting Element occurs that is attributed to mis-coordination of one or more of the Protection Systems addressed by the PSCS, would this automatically be considered a violation of PRC-027-1? Under Applicability, change “Distribution Provider (that own…” to “Distribution Provider (that owns…” Consideration should be given to including the following language, presently included in the Rationale for R1, in the body of the standard itself: “In cases where a single group performs an overall coordination study for a given Interconnecting Element, a single document that provides the requirements for a summary of the results of the PSCS is sufficient for use by all entities.” Similarly, consideration should be given to including the following language, presently included in the Rationales for R3 and R4, in the body of the standard itself: “In cases where a single group performs an overall coordination study for a given Interconnecting Element, a single document that describes the information listed in Requirement R3, Parts 3.1 and 3.3 below is sufficient for use by all entities.” In general, how would these exceptions impact an entity’s demonstration of compliance with Requirement R5? In Requirement R1, Part 1.2, the verbiage “…the associated Fault current(s)…” is ambiguous without additional guidance. Should this phrase be interpreted as “[a] listing of the single-line-to-ground and 3-phase Fault currents for the bus or Element at the Facility under study,” as stated in the Application Guidelines? If so, what would be an example of Fault currents for an Element, as opposed to a bus? In Requirement R1, Part 1.2, should “the contingencies used in the evaluation” be itemized as being required in the summary of the PSCS? This is mentioned in the Application Guidelines but not in the standard itself. Referring to Requirement R2, what if modeling errors are identified after a short circuit study is conducted? Is this an automatic violation of Requirement R2? In Measurement M4, change “…each owner of the Protection System…” to “…each owner of the Protection Systems…” or “…each owner of the Protection System(s)…” In Requirement R3, Part 3.1, the language “…or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s)” is ambiguous. What might be helpful is one or more examples (possibly within the Application Guidelines) of changes at other Facilities that would not require action pursuant to Requirement R3, Part 3.1. As the standard is written now, it would be easy to interpret that any change at any BES Facility would likely require action pursuant to Requirement R3, Part 3.1. It is not believed that this is the intent of the requirement. If it is the intent, then there would be no need to run short circuit studies at least every 60 calendar months because all changes impacting short circuit current at interconnecting

buses would already be addressed. In Requirement R3, Part 3.3, please confirm that the clause "…made due to failures of Protection System components" applies only to emergency replacements, and not necessarily to Misoperation investigations, commissioning, or maintenance activities. Consider two entities, Entity A and Entity B. Entity A submits a summary of a PSCS to Entity B pursuant to Requirement R1. Entity B then must respond pursuant to Requirement R4. As written, Requirement R5 appears only to require that Entity A address any identified coordination issues prior to implementation. However, Entity A may have identified issues associated with Entity B. It does not appear that the standard requires Entity B to take any action to address issues identified by Entity A. Provided this is a correct interpretation of the standard, would Entity A be permitted to implement the "proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s)" if Entity B elects not to address the issues identified initially by Entity A? On the other hand, if it is an incorrect interpretation of the standard, then additional clarification may be required. In the Application Guidelines, change "Examples of Protection Systems where technical justifications may be used include:" to "Examples of Protection Systems where technical justifications may be used include, but are not necessarily limited to:" In the Application Guidelines, under "Examples of Protection Systems where technical justifications may be used include," consider including "local breaker failure schemes" as a bullet under "Supervised overcurrent elements enabled by:" In the Application Guidelines, under "Examples of Protection Systems where technical justifications may be used include," consider changing "(i.e. transformer overcurrent, reverse power, etc.)" to "(i.e., transformer overcurrent, reverse power, generator phase-balance current, etc.)."
Individual
Michelle R DAntuono
Ingleside Cogeneration LP
Although we agree with the technical and logistical requirements incorporated into PRC-027-1, Ingleside Cogeneration still believes that an initial baseline of every interconnection is not necessary. We understand that older Fault studies may meet the intent of a Protection System Coordination Study, but believe where a PSCS does not exist; that commissioning and/or major upgrade testing records are sufficient. An extensive battery of studies and validations take place during these initiatives – and it is a reasonable assumption that the Protection System Fault sequencing was confirmed as well. If there was extensive evidence that Fault coordination was a major contributor to BES-level Disturbances, the effort to re-verify each Interconnecting Element may be justified. However, this evidence is not compelling – and the resources needed to support this effort can be applied to more pressing needs in our view. Should the TO find that the maximum Fault current has increased by 10% or more since their previous study, Ingleside will be prepared to engage in a coordinated follow-up review. The same is true if we or the Transmission Owner make a material change on either side of the Interconnected Element. Otherwise, we believe that the baseline effort serves only to satisfy an administrative purpose that makes little or any improvement in BES reliability.
Group
Nebraska Public Power District (NPPD)
Cole Brodine
Requirement R5 requires an entity "that received a response pursuant to Requirement R4 shall address any identified coordination issue(s) prior to implementing any proposed change(s) or addition(s) to the Protection System(s) associated with the Interconnecting Element(s)". In M9 it is stated that "Acceptable evidence for Requirement R5 is dated documentation (hardcopy or electronic fileformats) demonstrating that a response pursuant to Requirement R4 was received". It would be recommended that M9 instead read "demonstrating that IF a response pursuant to Requirement R4 was received…" since receiving a response in a timely or untimely manner is not in the control of the requestor so they should not be held accountable. R2 2.2.1 states "Within 30 calendar days after identification of a change of 10% or greater in either single line to ground or 3-phase Fault current, provide the updated Fault current values (Iscs) to each owner of the Protection System(s) associated with the Interconnecting Element(s)." This 30 day timeline seems too tight compared to its relationship with a 5 year study plan that will involve interface and model discussions with other entities. I recommend this timeline be changed to match the Requirement 1 R1.1.2 with a 12 month

timeline instead of 30 days. Rationale for R3 states “The drafting team contends that specifying a single time frame is not appropriate for the wide variety of conditions that will need to be evaluated.” I agree this statement is true. In light of this it would appear that 30 days for 3.2 and 3.3 seems too short. The Part 1.1.1 application guidelines also state: “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.” I believe it is reasonable not to implement additional standard requirements if data does not support it. Note that draft PRC-004-3 has provisions for entities to interface for misoperations so it would be reasonable to evaluate those timelines or eliminate misoperation references altogether from PRC-027 to avoid confusion. In addition R3.3 requires time lines for “emergency replacements” which do not seem realistic since these can be times of great flux. If PRC-004 has longer timelines it seems odd it is so tight in PRC-027. I recommend R3.3 be removed. At a minimum consider changing the time line such as R3 3.2 and if 3.3 from 30 and 90 days to match R4. This will help to minimize the numerous time lines.
Group
IRC Standards Review Committee
Charles Yeung
We have commented several times in the PRC standards proposals, that the requirements in PRC-001 having been retired, must be resolved. Since this has been dismissed as out of scope for the SDT, we ask the SDT to bring this issue to the Standards Committee to be addressed. NERC should develop a protocol to pass issues raised in standards development which may be out of scope of a SDT to be addressed formally by the Standards Committee. The Standards Committee should either respond to the commenter through the standards process available avenues, or provide a response directly to the commenter(s). We again urge the PRC SDT to work with staff and the PER SDT to submit an addendum SAR or a revised SAR to the SC for its approval to post for industry comment, then proceed to retire PRC-001-2 R1 by mapping it into an appropriate PER standard. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.
Individual
David Jendras
Ameren
On page 22 of the Application Guide item 1, replace ‘bus or’ with ‘Interconnecting’ to clarify by using the defined term Interconnecting Element. This yields: ‘A listing of the Protection System(s) owned by the entity performing the study that are adjacent to the Interconnecting Element at the Facility, and which were reviewed for coordination of protective relays as part of the study, including the contingencies used in the evaluation.’
Individual
Michael Falvo
Independent Electricity System Operator
As indicated in a number of our previous comments, we continue to disagree 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 or be mapped into another standard. The above view is consistent with the Independent Experts Review Panel’s recommendation. The SDT’s view that the retirement of PRC-001-2 Requirement R1 is outside the scope of this project and the scope of Project 2010-01 (Training) does not provide a satisfactory solution to this issue. In our view, the SDT of either this project or of Project 2010-01 should have submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise the appropriate PER standard accordingly. We offered the above comment about a year ago. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper or does not have a proper home. Once again, we urge NERC staff and the SDT to act now

to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.
Group
NYPA
Saul Rojas
The issue with PRC-027-1 revolves around the applicability of this Standard. In New York State, the NYISO (BA, RC, TOP, and TP) conducts semiannual short circuit studies after soliciting and incorporating additions, corrections, and comments from its member entities (Requirement 2). In addition, whenever an entity or outside developer wishes to add generation or transmission to the NYISO control area, the NYISO conducts the official studies, indicating any changes to circuit breaker duties as a result of such addition(s). These indications also go below a 10% threshold (Requirement 2). Lastly, though the technical validation of new or modified Protection Systems is performed by the TOs, GOs and DPs, in NYS the NYISO is involved from an oversight point of view (Requirement 3) – they require this data submitted to them so they can update the dynamic and steady state models – MOD-010 and MOD-011 – possible overlap of regulation.
Individual
Shirley Mayadewi
Manitoba Hydro
(1) R1, 1.1.3 - the opening of this part would be clearer if reworded to say 'Within an agreed upon time frame if notified....' Reference to 'change' should be to a ''proposed change or addition' to to be consistent. (2) R1, 1.1.4 - reference to 'change' should be to a 'permanent change' to be consistent. (3) R1, 1.2 - would be clearer if reworded to insert a (i) after the colon and a (ii) after 'or'. (4) M1 - would be clearer if reworded to insert a (i) before 'a dated PCSC' and insert 'or (ii) if relying on a technical justification' after achieved and in place of 'acceptable evidence of a technical justification'. (5) R2, 2.1 and 2.2 - bus(s) should be bus(es). (6) M3 - reference to 'present Fault current values' should be 'present maximum available Fault current values' to be consistent and reference to 'the equation' should be to 'the equation in Part 2.2'. (7) R3, 3.2 - the timeframe (within 30 calendar days of ..... schedule) at the beginning of the sentence would make the wording of this part more consistent with the rest of the drafting. (8) R3, 3.3 - reference to 'change' should be to the 'proposed change or addition'. (9) M5 - some of the language does not match up with the language of the requirement itself. R3 requires that 'details for any proposed change or addition' be provided, while the measure refers to 'a summary of the future project or technical specifications of the proposed changes'. (10) M6 and M7 - would be helpful for the timeline in these measures to be complete i.e. 'within 30 days of receiving a request' instead of just 'within 30 days'. (11) R4 - reference to 'other owner' would be more precise to say the 'Transmission Owner, Generator Owner or Distribution Provider(s) providing the summary or technical justification'. (12) R4 – it is unclear in R4 whether the receiving owner is the party that is identifying the coordination issues, or whether the receiving owner is noting the coordination issues that are identified by the owner of the summary or technical justification. (13) R5 - not sure the timing of this part works. It requests that the TO, GO or DP shall have received a response prior to implementing any proposed changes or additions, but 1.1.4 and 3.3 are requirements that relate back to permanent changes that have already been made.
Group
Hydro One Networks Inc.
Sasa Maljukan
We do commend the drafting team for moving this standard in the right direction. 1) The focus of this standard seems to be on the process of executing the Protection System Coordination Study (PSCS) rather than the content of the PSCS, implying that entities don’t need to be told how to do this task. However we feel that a significant reliability gap exists by not outlining what elements need co-ordination (in accordance with the NERC Technical Reference Document “Power Plant and Transmission Protection Coordination, Revision 1”) and this should best be addressed now rather

than later by a FERC NOPR. We are not intending for the standard to be a “How” document but rather a “WHAT” – as in What elements need to be coordinated. As identified by the drafting team, there may be no evidence of miscoordination between traditional protections that detect faults, but for coordination of say generator loss of excitation protection settings or out of step relaying during a fault condition, it is necessary for entities to understand whether these should be considered in their PSCS. At the very least this standard should specifically point to elements whose coordination requirements exist in other standards. 2) In line with comment 1 above, the Purpose statement is confusing. “To coordinate Protection Systems for Interconnecting Elements such that Protection System components operate in the intended sequence during Faults”. Are the protection systems involved specifically for the Interconnecting Element, or between Facilities connected by an Interconnecting Element? So for instance according to the NERC White Paper “Power Plant and Transmission System Protection Coordination”, stator ground protection may need to be coordinated with transmission system faults. Stator ground is a generator protection – so is that in scope of the PSCS specified in the standard since this protection is a generator protection, not an Interconnecting Element protection? 3) For Requirement R3.1, it is not clear what is meant by “Details….. associated with the Interconnecting Element or at other Facilities…..” What is the burden of proof associated with this requirement? In the long term planning horizon, is it implied this assessment be made through short circuit studies? We believe it would be proper to associate R3.1 solely with changes/additions “either at an existing or new Facility associated with the Interconnecting Element….”. Changes at other Facilities could mean 1, 2 or 3 busses away and we believe if these changes were significant, they would manifest themselves in a significant change in Fault current levels. Furthermore, in an audit, the burden of proof lies with the owner to show these changes “at other Facilities” don’t affect coordination. We suggest the following change to the wording: “Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnecting Element(s) where such changes result in a change of 10% or greater in either single line-to-ground or three-phase fault current as defined in R2.2.” Section 1.2 – Retention Period: This section specifies that the default retention period for this standard is “since the last audit”. Consequently, we don’t understand what is the purpose of the second sentence in this section (i.e. “For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.”) because there is no such instances.
Individual
Barbara Kedrowski
Wisconsin Electric Power Company
In draft #3 of the standard, there was requirement 4.2 which stated that “Prior to implementing any proposed change(s) or modifications associated with Requirement R3, Part 3.1 or Requirement 4, Part 4.1, affirm that the other owner(s) of each Facility associated with the affected Interconnected Element have accepted the Protection System(s) changes including the resolution of any identified coordination issues.” There does not seem to have this language in this draft. Was it the SDT intention not to require the entity proposing a change (defined in requirement 3.1) to get agreement with owners of Interconnected Elements prior to implementation?
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
Comment for Draft 4 of PRC-027-1 – Protection System Coordination for Performance During Faults Measure M9 requires the response to “address” any identified issues. Can the SDT provide examples of a range of responses that would “address” identified issues (even in a guidance document)? For example, if the TO does not agree with the entity that submitted the “identified issues” that the issues are truly valid, can the TO merely respond by a statement saying that the issues are unfounded. Would this be “addressing” the issue or would the TO in this example be required to provide more information such as additional study results? In addition, after providing such additional study results, would the TO then be done with addressing the issue, or would a follow-up

meeting be required if the entity that submitted its concern still disagrees? Please elaborate on what the SDT expects from “address any identified issues.”
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
The definition of interconnecting element needs to make clear that not only does it have to be a BES element to BES element connection, not just a BES element connecting two different entities. For example a TO to DP shared facility might have some BES elements that are shared, but that really just connect BES to non-BES equipment.
Individual
Michael Moltane
ITC
We vote "Negative" on Draft 4 of PRC-027-1 primarily due to enormous increase in administrative burden with no appreciable gain in system reliability. We agree with SDT there is reliability benefit to performing these tasks. However, as the SDT members stated at presentations to RFC Protection Subcommittee and to NATF Workshop, utilities are already doing this work. The SDT’s own rationale states “no evidence there is widespread miscoordination of Protection Systems”. Therefore, the only outcome of this standard is that utilities will greatly increase administrative burden to become auditable. Figure 5 Note statement “Transmission Owner S has no direct Protection Systems located at Station 1 that need to be checked for coordination with Generator Owner T” disagrees with Figure 5 and with the first sentence of the last two paragraphs. Figure 5 shows TO S owns breaker C in Station 1 and by implication also the Protection Systems associated with breaker C. The first sentence of the last two paragraphs specify the review of coordination of the Protection Systems of breakers C and D. Please remove the quoted sentence from the Figure 5 Note. We disagree with changing Figure 5 Interconnecting Element from the common bus to the connection between the bus and breakers. As is, R3 does not require TO R to act as a conduit for exchanging information between TO S and GO T. The last sentence of second-to-last paragraph in Figure 5 attempts to require TO R to act as the conduit for information between the other parties, but this is not found anywhere else in the standard. Please make the common bus the Interconnecting Element and remove statement in Figure 5 specifying TO R is to be a conduit for this information. As R3 is written, this requires each owner on the bus to share changes with each other owner. This should be a reasonable expectation. Why does Figure 3 not specify TO R develop settings for breakers A and B with DP S reviewing for coordination over breaker C and transformer? Why is this coordination around the Interconnecting Element not included? We had similar comments to Draft 3 but our question may have been misinterpreted. What is benefit of Facilities part b)? What is the SDT trying to exclude or include by using the statement “that require coordination”? Is it the intent of SDT in R5 to leave open possibility of implementing proposed change without receiving a response pursuant to Requirement R4? R5 only requires addressing identified coordination issues if the entity “received a response pursuant to Requirement R4”. R4 allows the entity 90 days to respond. The entity making the change could implement the change in this 90 day window without receiving a response and still be compliant. R1.1.3 allows the two parties to reach agreement on the PSCS date which may typically allow time for such exchange, but the entity making the change could move up the change implementation date or the agreed upon date could be less than 90 days prior to the implementation date. R3.3 and R1.1.4 leave out a requirement for a PSCS by the owner with the emergency/commissioning change. R1.1.4 specifies only the party “notified of a change as described in” R3.3 shall perform a PSCS. Is this the intent of the SDT?
Individual
Winnie Holden
PSEG
1.Replace “technically justify” and “technical justification” language is several places. a.Parts 1.1.2, 1.1.3, and 1.1.4 require an owner, as an alternative to performing a PSCS, to “technically justify why such a study is not required.” We recommend that the phrase “technically justify” be replaced

with “state” in Parts 1.1.2, 1.1.3, and 1.1.4. The phrase “technically justify” conjures up detailed documentation, whereas an expert’s statement that is read by another expert (see R4) may be totally understandable and satisfactory. b.The last sentence in M1 should have the phrase “of a technical justification” stricken so that it reads “Acceptable evidence for not performing a PSCS as specified in Parts 1.1.2, 1.1.3, and 1.1.4 may include, but is not limited to, documented engineering analyses or assessments that demonstrate the change in Fault current or the proposed system change does not impact any aspect of coordination.” c.Part 1.2 should also have the phrase “technical justification” removed and be rewritten as follows: “Within 90 calendar days after the completion of Requirement R1, Part 1.1, either provide to the other owner(s) of the Protection System(s) associated with the Interconnecting Element(s): a summary of the results of each PSCS performed, including, at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or a statement why a PSCS is not required. d.M2 should have the phrase “technical justification” replaced with “statement why a PSCS is not required.” e.In R4, an owner’s “technical justification” must be confirmed by the other owners of Facilities with protection Systems associated with the Interconnecting Element – either with no issues or with issues noted (see the last two bullets in R4). Since one owner’s experts will be communicating with another owner’s experts, a statement why a PSCS is not required is sufficient. We request that “technical justification” be replaced with “statement” the first sentence in R4. We also request that “technical justification” be replaced with “statement why a PSCS is not required” the third bullet fourth bullet in R4. 2.In R2, the team’s rationale for naming the Transmission Owner as the entity responsible for performing the short circuit studies is that they maintain the data necessary to perform the studies – see the R2 textbox. This statement is not correct. Short circuit data under MOD-032-1 will be collected by a Planning Coordinator or a Transmission Planner. In addition, Generation Owners are responsible for some of the data – see Attachment 1 in MOD-023-1, “short circuit” column. However, short circuit data will be used by Transmission Planners in TPL-001-4. In that standard, Transmission Planners are required to perform short circuit analyses to determine whether existing or planned circuit breakers have the interrupting capability for the calculated Fault current. See TPL-001-4 Requirement R2, Part 2.3 as well as Part 2.6, which identifies when prior studies may be used. The SDT should recognize the requirements in TPL-001-4 and take advantage of Fault Current calculations already required by this standard. By having the Transmission Planner perform the Fault current calculation, a consistent short circuit database across a large footprint, such as PJM, will be used. Therefore, “Transmission Owner” should be replaced with “Transmission Planner” in R2. In addition, “Transmission Planner” should be added as an Applicable Entity.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; and PPL Generation, LLC, PPL; Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. There remains the technical issue that TO changes do not typically affect GOs’ Protection System configurations or settings. Requiring GOs to perform PSCSs would not improve system coordination during faults, especially since everything involving tripping elements in the intended sequence (the stated purpose of PRC-027-1) is in the TO’s system. Currently, the only inputs that GOs need from TOs, are the fault current at interconnecting buses (affects the GO’s arc-flash studies) and the grid X/R ratio. PRC-001 coordination for TO changes would typically consist of GOs obtaining these two values and not requesting and analyzing the detailed TO information cited on p.23 of PRC-027-1 (“power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings”). Consequently, GOs should have no Protection System coordination duties other than reporting and receiving information on planned changes prior to implementation as per PRC-001. In concept, the individual requirements of PRC-027-1 are logical; however, significant efforts will be required for documentation of coordination across Registered Entities which will be required to achieve the totality of (R1-R5) intent. The

concern is that actual system coordination is currently built in to TO/GO processes and that the PRC-027-1 requirements do no more than place focus on documentation of such processes of coordination activity rather than the system coordination itself.
Group
Seattle City Light
Paul Haase
Sacramento Municipal Utility District (SMUD)
Seattle has concerns with this draft in addition to those identified in SMUD's comments. In particular, the present draft creates difficulties for entities with short transmission lines that require use of communication-assisted (pilot) relaying schemes in order to provide proper sectionalizing (coordination) of the transmission system during a fault event. The draft does not address the coordination of pilot schemes, and their backup relays (67N, e.g.). The 67N relays, located at the different buses, cannot be coordinated in our system (and others). In the absence guidance in the draft, Seattle recommends that the language be clarified to allow miscoordination of the backup relays as long as the pilot scheme is in place.
Individual
Alice Ireland
Xcel Energy
1. It is assumed that PRC-027 PSCS requirements will also apply for Interconnecting Elements between the Transmission System and the high side of the final aggregating step up transformer for BES dispersed generating facilities as described in Inclusion I4 of the recently passed BES Definition. If this indeed the case, an additional bullet should be listed in PRC-027 R3.1 as follows: [• At BES dispersed generating facilities, changes to the aggregating step up transformer or aggregating system which result in a change in impedance.] It may also be beneficial to include a diagram of a typical dispersed generation facility and relevant discussion in the Application guideline similar to that provided for the conventional generator configuration as shown on Fig 2 on page 28 of 32 of the standard. 2. PRC-005-2 and PRC-005-3 have recently been approved by NERC and both of these versions of the Protection System Maintenance Standard exclude the protection systems for power plant system-connected auxiliary transformers from their applicability. This exclusion of the system-connected auxiliary transformer from PRC-005 maintenance requirements is also described in the associated PRC-005 Supplementary Reference Document. In contrast, PRC-025 was also recently approved by NERC and specifically includes relay loadability setting requirements for relays protecting generating plant system-connected auxiliary transformers which are capable of providing plant electric loads during full power operation of the plant. Is it the intention of the drafting team that PRC-027 PSCS requirements apply to Interconnecting Elements that serve to connect the Transmission System to generating plant system-connected auxiliary transformers such as 345 KV line connecting a substation 345 KV breaker and a half scheme node to a plant 345KV/4KV auxiliary source transformer? We do not have a strong opinion whether a PSCS should be required for such interconnections. However, based on the inconsistent treatment provided to these system-connected auxiliary transformers in other standards as cited above, we believe it not only desirable but necessary that the PRC-027 application guideline explicitly state the drafting team's intentions concerning PSCS requirements for the interconnection between the Transmission System and power plant system-connected auxiliary transformers.
Group
Dominion
Connie lowe
Dominion has no comments and supports PRC-027-1.
Individual
Anthony Jablonski
ReliabilityFIrst

ReliabilityFirst votes in the affirmative for the draft standard but offers the following comments for consideration: 1. Requirement R1, Part 1.2 - ReliabilityFirst believes the reference to "… technical justification pursuant to Requirement R1, Part 1.1" should be changed to correctly reference Requirement R1, Part 1.1.2 and 1.1.3. 2. VSL Requirement R1, Part 1.2 - Requirement R1, Part 1.2 specifically requires "…at a minimum, the Protection Systems reviewed, the associated Fault current(s) used, any issues identified, and any revisions or actions proposed; or the technical justification.". For clarification, if an entity fails to include one of these items in the summary more than 30 calendar days, does the entity fall under the "Severe VSL"? If this is not the SDTs intent, the VSLs will need to be drafted to address entities failing to include the mandatory items.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
ATC is recommending an affirmative vote with the following clarifying comments: a. The text in sub-requirement R1.1.2. states "…10% or greater change in Fault current..," however, it is unclear what is considered the baseline. ATC recommends that this be clarified so that it is stated against what point in time the change is being measured. b. The text in Requirement R5 currently states "…shall address any identified coordination issue(s)…" which is vague and could lead to the unlikely event of an uncooperative party either stalling or prohibiting the work. ATC recommends this be clarified or re-written as "…shall address or acknowledge any identified coordination issue(s)…"
Individual
Andrew Z. Pusztai
American Transmission Company
ATC is recommending an affirmative vote with the following clarifying comments: a. The text in sub-requirement R1.1.2. states "…10% or greater change in Fault current..," however, it is unclear what is considered the baseline. ATC recommends that this be clarified so that it is stated against what point in time the change is being measured. b. The text in Requirement R5 currently states "…shall address any identified coordination issue(s)…" which is vague and could lead to the unlikely event of an uncooperative party either stalling or prohibiting the work. ATC recommends this be clarified or re-written as "…shall address or acknowledge any identified coordination issue(s)…"
Individual
Chris Scanlon
Exelon Companies
Consistent with previous comments, we continue to believe that PRC-027 is overly complex and its implementation will result in an unfair burden to registered entities that will not provide a commensurate increase in BES Reliability. The detailed flowchart included in the draft depicts a complex relationship between the requirements that will be difficult and costly to document in actual practice. Each protection activity that requires PRC-027 compliance tracking will have a unique trajectory through the flowchart creating a complex documentation record to prove that compliance efforts have indeed satisfied the flowchart. That such an intricate flowchart is required to explain the compliance process illustrates this point. From the standpoint of Transmisson Owner, we believe that developing a process to comply with this standard will prove to be a costly venture requiring additional staff just to track the status compliance items and doing little to improve the reliability of the BES. As written, the standard continues to be vague and in practice will be subject to individual interpretation by entities and Compliance Authorities alike. Requirement 3.1 does not provide sufficient clarity about what magnitude of impedance change would trigger an entity to provide details to other entities associated with a Protection System of an interconnected element. We believe that the decision of whether a change is significant should be left to the sound engineering judgment of the Protection engineers. We suggest the following modification to R3.1, Changes to a transmission system Element that result in a significant change in sequence or mutual coupling impedance. Changes to generator unit(s) that result in a significant change in impedance. Changes to the generator step-up transformer(s) that result in a significant change in impedance. Requirement 5 What will qualify as evidence of "addressing" an identified issue? Measurement 9 is

not helpful in providing clear direction to entities as to what is acceptable evidence that an issue identified by R4 has been addressed. What options are availble if an entity receiving notification of an issue does not agree there is an issue?
Group
ACES Standards Collaborators
Jason Marshall
(1) We continue to believe that this standard should only require coordination between separate companies and not separate functional entities that may be under one corporate umbrella. We are particularly concerned about coordination requirements placed on smaller entities such as generation and transmission cooperatives where a single protection engineer may be responsible for protection system coordination for all transmission, generation and distribution interconnections. Having to document coordination among a single protection engineer is an unnecessary compliance burden on these small entities and the reliability benefit is not commensurate with the additional compliance costs required of the small entity. We ask the drafting team to consider an exception process for small entities to relieve them of unnecessary compliance burdens if this requirement persists. (2) We disagree with the definition of "Interconnecting Element" because the second part of the definition would require a Registered Entity registered as multiple functional entities to coordinate with itself. This definition does not take into account smaller entities that may be registered for multiple functions, but still only have a single protection system engineer. This poses an issue for smaller entities to prove compliance for this coordination among its functions. For example, why should such a small entity be required to show additional evidence of coordination between its functions of TO, GO, and DP for its relaying schemes that a single Protection System engineer determined was appropriate. The settings and schemes themselves are evidence of coordination, and this standard is asking for additional documentation that does not benefit reliability. (3) Requirement R2 should specify an initial performance period for initial compliance consistent with R1. R1 establishes that a Protection System Coordination Study should be completed within 60 months of the effective date of the standard. However, R2 only requires that the TO perform a short-circuit study once every 60 months. Thus, does this mean that the initial short-circuit study for compliance purposes has to be completed prior to the effective date of the standard, or 60 months after the effective date or some time period in between? Given this ambiguity, there will be inconsistent compliance outcomes from region to region and registered entities are bound to interpret this differently than compliance enforcement authorities. To avoid similar issues of compliance violations when PRC-005 was first implemented, we request that the drafting team establish a clear initial compliance period in the implementation plan. (4) R2, part 2.1: We recommend removing short circuit studies for this standard, as there are other standards that require short circuit calculations and data submittals, such as the MOD-B project and short circuit studies and analysis that are required under TPL-001-4. These other standards address short circuit data and analysis and we are concerned of potential overlap and possible double jeopardy of including short circuit studies in PRC-027. (5) We have concerns with the use of "proposed change or addition" for Part 3.1 and believe it will lead to inconsistent enforcement. The term "proposed" is vague. When does an idea for a modification become a proposed change that must be communicated to other TOs, GOs and DPs? For example, if a new generator interconnection is requested and studies indicate that it would require a transmission modification that changes a transmission system Element and alters it impedance, is this a proposed change? When would it become a proposed change, when the interconnection agreement is signed? When the request is submitted? The requirement is not clear which will lead to different opinions between registered entities and compliance enforcement personnel. Additional clarity is needed for when a change must be communicated. (6) The Guidelines and Technical Basis section of PRC-027 has raised several questions. In the purpose, the second paragraph states that "this standard requires that separate registered entities communicate with each other to coordinate Protection System components on existing Interconnecting Elements," however, we are concerned that the definition of Interconnecting Elements is contradictory. Section "b" of the definition is based on the same registered entity that represents multiple functional entity responsibilities. Which is it? The technical justification states that the standard should apply to separate entities, but the proposed definition states that the standard applies to separate functions, even if those functions are registered to a single entity. We ask that the drafting team provide clarification and suggest that the standard is

applicable to corporate entities and not separate functional entities within a corporate entity. (7) We believe Part 3.2 meets P81 criteria and it should be struck. It is administrative in nature and meets criterion B4 - Reporting because it requires reporting to a third party and the reporting does not provide a material reliability benefit. (8) Requirement R4 meets P81 criteria and should be struck. It is administrative in nature and provides no reliability benefit. More specifically, it meets criterion B4 - Reporting because it requires reporting to a third party without material reliability benefit and criterion B1 – Administrative because it requires responsible entities to perform an administrative function that does not support reliability and is needlessly burdensome. This requirement should be struck. The real reliability requirement is to address coordination issues, which is already covered in R5. (9) The technical justifications for not updating the PSCS provided on page 21 of the Application Guidelines should be codified in the standard. We agree with the technical justifications. For example, there is no need to update a PSCS for a differential protection system for a greater than 10 percent change in fault current per Part 1.1.2. The approach could be modeled after PRC-023 Attachment A. (10) Thank you for the opportunity to comment.
Group
Duke Energy
Colby Bellville
Duke Energy would like to thank the SDT for its efforts on this project.
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
The proposed standard is incorrectly defining the tap line serving a distribution load as an “Interconnecting Element”. The tap line in this case is not a BES Element. PRC-027-1 should only apply to interconnecting TOs or to interconnecting TOs and GOs. The only coordination that makes sense between the TO and the DP is making sure the TO does not trip its BES Element (line) for a fault located within the DP. In this case, the TO and DP would be responsible for detecting and coordinating for a fault on a non-BES element (which is not an “Interconnecting Element” as defined by the proposed standard). The proposed standard seems to attempt to redefine a DP-owned transmission Protection System as a system that simply detects a fault on a BES Element (Interconnecting Element) and requires coordination. That is not consistent with the FERC-approved interpretation of what constitutes a Protection System; i.e., detect BES fault and interrupt BES fault current. IMEA appreciates the need for proper relay coordination between the players (TOs and GOs) on the grid, but this proposed standard seems to incorrectly apply a coordination requirement to the interconnected DPs. Also, during the 12/5/13 PRC-027-1 Webinar, it was noted that the Protection System Coordination Study (PSCS) specified in Requirement 1 must be performed by each party at the ends of an Interconnecting Element. This seems like overkill. The owner of the Interconnecting Element should take the lead on the PSCS, with coordination/support/cooperation of course provided by the interconnected party.
Individual
Joe Tarantino
Sacramento Municipal Utility District
• Requirements are not ‘self-contained’ there are several requirements that reference another process in other requirements; • Allegedly this standard only applies to interconnections, this is not clearly evident in the Interconnected Element definition; • Requirement R1.2 references another owner. SMUD views this as an administrative burden having to document to the ‘other owners’ communication when the ‘owners’ Protection System Coordination Study is conducted by one responsible party. • Several of the requirements contain a ‘zero defect’ concept where if a date is missed it results in an automatic violation.
Group
Florida Municipal Power Agency
Frank Gaffney

To us, relay coordination is very important to reliability, more so than many other standards. So, at least in FMPA's view, this standard may actually not go far enough in two ways: 1) Clearing the fault within the critical clearing time: yes, the TPL standards require that we plan the system to be stable considering actual fault clearing times with consideration of a failure of a protection system looking > 1 year into the future; and yes, FAC-011 requires us to define SOLs that are stable in consideration of clearing times for single contingencies (but without protection system failure); but, there is little in the standards that requires us in the operating horizon to make sure we are clearing a fault fast enough to avoid instability for a single line to ground fault with a protection system failure. Maybe PRC-027 is not the right standard to accomplish this goal; however, we would have liked to have seen the purpose of this standard talk about clearing the fault quickly considering a protection system failure as the highest priority, with the proper sequence of tripping as a secondary priority. As protection engineers, we have seen times where we purposely would allow over-tripping for backup protection for some faults to make sure we cleared the fault within the critical clearing time. The standard as proposed makes "operate in the intended sequence" the only priority of the standard and as such may not allow continuation of this practice. 2) Coordinating all BES protection, not just at the boundaries: Another important consideration is that fault clearing, and proper sequencing of fault clearing, is important at all parts of the BES, not just at the boundaries between registrations. The standard as written follows the example of the existing PRC-001 it is replacing which requires coordination only at the boundaries between entities. The standard does expand this scope by requiring vertically integrated utilities to define boundaries between their registrations and coordinate protection systems across those boundaries (e.g., between the generators and the transmission at the interconnection) (as we have witnessed from the GO TO effort, defining those boundaries is not straightforward and is open to conflict). However, as stated previously, what makes the boundaries between registrations different than any other location on the BES from a critical clearing time and sequence of operation perspective? If Protection System coordination throughout the BES was instead required, there would be no need to defined these boundaries and would reflect its importance to reliability. FMPA made these same comments on the prior ballots of this standard, but, to no avail on the SDT. It strikes us as quite odd, when we compare the recently balloted PRC-002 on disturbance monitoring, which has de minimus impact on reliability, and this PRC-027 which is very important for reliability, that the PRC-002 standard is longer, more detailed, and in some ways more onerous (14 requirements) than this proposed PRC-027 (4 requirements). FMPA believes that PRC-002 should not be a standard at all due to its de minimus impact, but also believes that PRC-027 does not go far enough due to its important to reliabiliy. FMPA believes that priorities are misplaced in standards development.
Group
SPP Standards Review Group
Robert Rhodes
We are concerned that the standard as proposed offers a formalized, very prescriptive structure without providing significant reliability gains since most of the requirements are currently captured by the industry in good business practices. We would prefer to have a more generic, less prescriptive standard that provides more of a guideline of what coordination is required rather than the complicated, involved documentation that is required in the current draft. We believe Requirement R1.1.1 is duplicative with Requirements R2 and R2.1 because they are both based on a 60-calendar month time frame. Furthermore, R1.1.1 is a one-shot requirement that would no longer be applicable after the first 60-calendar month cycle. Therefore R1.1.1 should be deleted from the standard. We are confused by the language in Requirement R1.1.2 which appears to require a PSCS within 12 months of determining, or being notified of, a 10% change in fault current. First of all, haven't you already done the study when you determine that the change exists? Secondly, does this require a study within the first 12 months following the standard becoming effective if no study currently exists? Otherwise, a study is not required for 60 months plus the 12 month grace period. Additionally, for smaller entities, especially municipals or cooperatives, without full-time staff to conduct full-blown PSCSs, 12 months may be imposing a very tight schedule on them given considerations for seasonal issues, vendor availability, bidding and approval processes. On Page 24 in the Guideline and Technical Basis section under Requirement 4 in the 1st line, insert a space between R4 and directs. We suggest that all references to calendar days or calendar months which

are preceded by a specific number of days or months be hyphenated. For example, 30-calendar days, 60-calendar days, 12-calendar months, 60-calendar months, etc.
Group
Southern Company: Southern Company Services, Inc; Alabama Power Company; Georgia
Wayne Johnson
a) R3 should state what is to be provided. As such “the following information” after “provide” in the 1st line of R3. b) R3.1 is confusing because of the use of “either” and two instances of “or” which follow. Suggest removing the ‘either’ and modify ‘existing or new Facility’ to ‘existing/ new Facility’ Also, no colon introduces the bulleted text c) R3.3 wording needs improvement. A reader is looking for what information must be provided as they goes from R3 to 3.1, 3.2, and 3.3. Beginning 3.3 with “Within 30…” makes it difficult to determine what is to be provided. Suggest moving ‘within 30 days’ to the end of the sentence. d) It would be helpful if, where possible, the boxes in the Flow Chart indicated the owner to which it applies. For instance, the box for R2.2.1 should say ‘The TO shall ….’ e) In order to prevent potential confusion, would the SDT consider modifying R4 & R5 to include exclusions for a PSCS performed as a result of “other changes” specified in R3.3. f) The flow chart is helpful to demonstrate the flow of the desired process and the triggers for study review. Minimizing the twists and turns in the presentation would make it even better. Also, there is a short circuited section around box R2.2.1 and the “receive notice of > 10%…” that should be corrected. Please consider replacing that section with the diagram provided under separate cover to the Chair and NERC Standards Coordinator.
Group
Western Electricity Coordinating Council
Steve Rueckert
Over time, Part 1.1.1 of Requirement R1 will become meaningless. After the standard has been effective for five years, it will be outdated unless the intent is to continue to assess whether or not all entities have completed all Protection System Coordination Studies for the first time. Is this something that should be in the implemetnation plan rather than a requirement?
Individual
Rich Salgo
NV Energy
In the rationale statement for R1, part 1.1.1, the SPCSDT acknowledges that there is no “widespread miscoordination of Protection Systems associated with Interconnecting Elements that warrants a shorter time frame,” yet nevertheless specifies a requirement to conduct a PSCS within 60 months for instances where no PSCS exists. Given that there is no widespread miscoordination issue, we suggest that suitable evidence other than a formal PSCS should suffice. Suggest the following language for 1.1.1: "Within 60 calendar months after the effective date of this standard, if sufficient evidence of coordination for that Interconnecting Element does not exist." Also, we are concerned about the Applicability section as it pertains to interfaces between the transmission and distribution systems of an Entity. We believe that, for example, a 138/12.5kV substation transformer should not qualify as an Interconnecting Element, and request clarification in the Applicability section that provides some certainty on that point.
Group
US Bureau of Reclamation
Erika Doot
The Bureau of Reclamation (Reclamation) appreciates the drafting team’s efforts to address stakeholder concerns that an engineering department may perform analysis from both the Transmission Owner (TO) and Generator Owner (GO) perspective. However, adding a note to the rationale for R1, R3, and R4 that “[i]n cases where a single group performs an overall coordination study for a give Interconnecting Element, a single document … is sufficient for use by all entities” does not appear to fully address the concern. For example, one signed and dated document is

unlikely to demonstrate that the GO-arm of the entity reviewed the summary results of the study within 90 days as required by R4. Reclamation requests that the requirements and measures clarify how to document the coordination of a study when an entity acts as a GO on one side of an Interconnecting Element and a TO on the other side of the Interconnecting Element. Reclamation also requests clarification on the scope of R3.1, which references any change at a facility that "modifies the conditions used in the coordination of Protection Systems associated with Interconnecting Elements." The Application Guidelines associated with R1 suggests that technical justifications may be used to exclude certain differential elements, distance elements, supervised overcurrent elements, and reverse power, definite time, and/or time overcurrent elements from the Protection System Coordination Study (PSCS) requirement. However, R3 appears to require notifications for new installations or modifications of these types of elements when they do not impact conditions for detecting and clearing faults and would not require a PSCS. Reclamation suggests that R3.1 be updated to refer to notifications "when the proposed change impacts the conditions for detecting or clearing faults" rather than "when the proposed change modifies the [seemingly any] conditions … used in the Coordination of Protection Systems." Reclamation believes that R3.1 should require, "Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnecting Element; or at other Facilities, when the proposed change impacts the conditions for detecting or clearing faults on the BES elements used in the coordination of Protection Systems associated with the Interconnecting Element(s)."
Group
Bonneville Power Administration
Andrea Jessup
BPA reiterates our previously stated concerns expressed in draft 3 comments. BPA concerns stem from two basic issues. First, PRC-027 prevents us from using our judgment to determine when and how to review relay coordination on our interconnections with neighboring entities. This reduces our efficiency and eliminates the flexibility that allows us to most effectively interface with each of our neighboring entities. If it could be shown that there would be an increase in the reliability of the bulk electric system based on this standard, perhaps this standard would be acceptable, but we are not aware of any problem that this standard will correct. The second basic issue that causes BPA concern with this standard is that it contains requirements for which the details of compliance are not adequately addressed. BPA recommends that the meaning and details of the terms Interconnecting Element, Protection System Coordination Study, and interconnecting bus be more clearly defined. These are some of the major terms used in the standard. The standard also relies heavily on the Guidelines and Technical Basis to explain its meaning, but this too falls short and cannot possibly cover every different situation that will be encountered in the application of the standard. Because of these fundamental issues, BPA finds PRC-027 unacceptable. BPA's suggestion is to draft a much more basic standard. A simple requirement, such as Each Transmission Owner (TO) that owns a Protection System which requires coordination with a Protection System owned by a neighboring TO to prevent the scheme from misoperating shall reach agreement with the neighboring TO on how to set the protective relaying scheme in order to minimize the possibility of it misoperating, along with some simple measures for documentation would be sufficient to insure that neighboring entities work together to coordinate their protection systems while still allowing for flexibility and engineering judgment to be applied.
Individual
John Brockhan
CenterPoint Energy
1. For a Registered Entity that represents multiple functional entity responsibilities, CenterPoint Energy believes the proposed definition for Interconnecting Element, as stated, would require an entity to perform a Protection System Coordination Study (PSCS) on every BES Element in its system. We recommend the wording in item "b)" of the definition be deleted. The concern the SDT appears to be addressing is the coordination of transmission protection systems with generation protection systems. We do not believe a mandatory requirement is needed to address communication and work processes within a vertically integrated entity. NERC Reliability Standard PRC-004 addresses transmission and generation misoperations and is a vehicle that is already in

place that can be used to address Protection System coordination needs, should root analysis identify such a need. In a vertically integrated entity, a corrective action plan would include both transmission and generation protection aspects. 2. CenterPoint Energy recommends that Distribution Providers be removed from the Applicability section. It appears that there would be very few, if any, distribution protection systems that would be applicable to the proposed requirements. We are not aware of any distribution protection systems that must be coordinated with transmission Protection Systems to allow for the proper functioning of the transmission Protection Systems. 3. CenterPoint Energy recommends that the trigger to conduct a Protection System Coordination Study for a 10 percent or greater change in fault current be only for increases in fault current; that is, decreases in fault current should not require entities notify other entities and not require the entities to conduct Protection System Coordination Studies. Protection Systems must operate for a variety of reduced fault current levels in normal system operation, as well as operation during and after major storms. For example in normal operation, there is a substantial decrease in fault current when a generating unit or an autotransformer is unavailable. In storms (hurricanes, extreme cold, etc.), even greater decreases in available fault current can occur. 4. While coordination of Protection Systems is a reliability consideration, CenterPoint Energy recommends reevaluating the need for this standard with consideration that this could instead be addressed by misoperation analysis. NERC Reliability Standard PRC-004 addresses transmission and generation misoperations and is a vehicle that is already in place that can be used to address Protection System coordination needs, should root analysis identify such a need.
Individual
Brian Evans-Mongeon
Utility Services
The applicability section for Distribution Providers requires more specificity. How will a DP become aware that their Protection System requires “coordination for isolating” faulted Interconnecting Elements? Suggest adding language requiring the owner of the Interconnecting Element to notify the Distribution Provider that their Protection System is required to isolate faults on the Interconnecting Element. This will place the burden on the owner of the protected Interconnecting Element to ensure that element is properly protected.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
R5 does not require that “identified issues” associated with technical justifications be addressed. We believe the addressing of those needs to be included.
Individual
Spencer Tacke
Modesto Irrigation District
The definition of Interconnecting Element needs to be revised, specifically part b). It is unclear what the intent of part b) is. If you interpret part b) the way it is written, it seems that part b) would exclude BES elements that don't join separate entities if the entity is just a transmission owner, or just a generator owner, etc. Thank you.

Additional Comments:

Tampa Electric
James Rocha

The violation severity level even on insignificant elements should not be based on time but based on the risk to the BES. The requirements create a large documentation and scheduling burden without improved reliability, if passed as proposed.