Individual or group. (67 Responses)
Name (41 Responses)
Organization (41 Responses)
Group Name (26 Responses)
Lead Contact (26 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (16 Responses)
Comments (67 Responses)
Question 1 (44 Responses)
Question 1 Comments (51 Responses)
Question 2 (45 Responses)
Question 2 Comments (51 Responses)
Question 3 (45 Responses)
Question 3 Comments (51 Responses)
Question 4 (43 Responses)
Question 4 Comments (51 Responses)
Question 5 (44 Responses)
Question 5 Comments (51 Responses)
Question 6 (39 Responses)
Question 6 Comments (51 Responses)
Question 7 (40 Responses)
Question 7 Comments (51 Responses)
Question 8 (0 Responses)
Question 8 Comments (51 Responses)

Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA continues to believe the greater purpose is to ensure faults are cleared within their critical clearing times and that such consideration is greater than operating within the desired sequence. The same comment would apply to the definition of Protection System Coordination Study.
No
The definition poses a problem with the second bullet. It is relatively easy to determine the "boundaries" between separate Registered Entities. It can be difficult to determine the boundaries between where an entity's separate registrations begin and end. Just look at how difficult determining the boundaries of the BES is, and witness the challenges of the GO/TO project where the boundaries between GO and TO are/were not clear. This standard now requires us to also draw the boundary between TO and DP. For example, let's take a step-down

transformer to distribution that is connected to a ring bus or breaker-and-a-half scheme. Typically, the high side relays for the transformer will be connected to the current transformers on the breaker bushings within the bus arrangement, which are part of the BES. Those relays are not only there to protect the transformer (not BES), but, also the bus section within the ring or breaker-and-a-half scheme (which is BES). So, are those relays (e.g., differential, directional overcurrent looking into the transformer) owned by the TO or DP registration? It also seems to FMPA that the reliability objective should not be limited to coordinating relays at just the "boundaries"; so, maybe one way to solve the boundary issue is to ignore it and just require a Registered Entity to coordinate its relays that protect the BES. This would expand the scope of the standard even more than the current PRC-001 to the proposed PRC-027, but, it would meet the reliability objective better. Another way to do it is to coordinate all at > 200 kV following PRC-023, and coordinate at the boundaries between entities (not registrations), at all BES.
No
Five (5) years seems way too long for an initial coordination study. We should pick a period of time that both industry and FERC will likely approve, maybe something like two (2) years. Other comments on R1: FMPA's interpretation of the Applicability combined with the standard is that remote back-up protection is included as it was "installed for the purpose of detecting Faults on Interconnected Elements". This becomes ambiguous for directional, inverse time ground current protection whose reach can vary with ground current, or with such relays and zone distance relays with changes in system configuration. FMPA's interpretation is that the Applicability is to the maximum reach of such relays; is that the intent of the SDT? Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?
Yes
No
Bullet 1.2 is ambiguous in its use of the term "owner"; especially in combination with the definition of Interconnected Element that makes the distinction between different registered functions within the same entity. Is the owner the entity, or the registered function? We assume the "owner" is the entity; is that the intent of the SDT?
Yes
Yes
Group
ISO RTO Council Standards Review Committee
Greg Campoli, Chair

No
It seems like the scope of the standard as stated in the purpose statement can be misunderstood. Later in the proposed standard, the purpose is narrowed: “Fault clearing is the only aspect of protection coordination that is addressed by Reliability Standard PRC-027-1.” The SDT should consider revising the purpose to reflect the scope of this standard, e,g. “,,,operate in the desired sequence to CLEAR faults.” 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. This is a training requirement and as such, it should be transferred to the appropriate PER standards. The SRC supports the project for removing this requirement and moved into the PER standards..Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are “familiar with” the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to comment submitted by some commenters, the SDT indicates that it “…recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.” We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee’s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee’s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. We urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.]
Yes
Yes
SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.

Yes
SRC chooses not to respond to this question, please disregard the response as it was selected in error and could not be deleted.
No
R4 requires all affected parties to agree to a solution. However the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the prospective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave a significantly loaded transmission line in a potentially single end situation by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? Should there be a notification requirement to the TOP?
Yes
Yes
Individual
Dan Roethemeyer
Dynegy
Yes
No
•Please provide more examples of interconnected elements, especially for a merchant generator. It’s not clear if the protection system study should address protection systems for just the generator breaker or also the generator step up transformer, unit auxiliary transformer, or the generator itself. Perhaps this information belongs in the Application Guideline.
Yes
Yes
Yes
Yes
Yes

If a Generator Owner does not own a Protection System associated with an Interconnected Element, does the Standard apply? For instance, if the generator breaker opens only for faults on the Generator Owner side of the breaker (i.e., GSU or generator faults). Is it expected most GOs will own Protection Systems associated with an Interconnected Element?
Group
Northeast Power Coordinating Council
Guy Zito
No
The wording is redundant. Coordinating Protection Systems mean operating in the desired sequence during faults. The Purpose should just read “To coordinate Protection Systems for Interconnected Elements”.
Yes
Yes
60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
Yes
60 months is an adequate and appropriate period which balances the interest of reliability with the economics related to engineering costs.
No
R4 requires all affected parties agree to a solution. However, the applicable Functional Entities that PRC-027 impacts are limited only to the TO, GO and DP. When designing a protection system scheme to clear faults, a satisfactory solution in the perspective of a TO, GO and DP may have unintended consequences for the Transmission Operator. For example, what if the solution is to leave what in normal operation is a significantly loaded transmission line in a potentially open terminal configuration by leaving a ring bus configuration open after clearing a fault? How can the TO, GO and DP ensure their agreed upon solution is manageable for the Transmission Operator? There should be a notification requirement to the TOP.
Yes
There should be consistency between standards on this point.
No
To specifically address Requirement R1, the Measure should be rewritten to stress that there be familiarity with the protection system schemes applied in its area. Suggest revising the Measure for Requirement R1 to read: Each Transmission Operator, Balancing Authority, and generator Operator shall have evidence that its appropriate personnel were made familiar with protection systems in its area. That can be made easily auditable by having written summaries of the schemes, and have personnel sign offs after reading.
PRC-027-1 in its entirety needs a quality review. Requirement R2 is not written correctly--it does not refer to the entities first. Also, each Requirement has multiple numbered Measures.

The Requirement also states that the functional registration (e.g. GOP) has to demonstrate compliance, not the individual operators. If it is the intent of the Standard that each individual operator of an entity be familiar this should be added. By stating the functional registration as opposed to the individuals, it could be interpreted that as long as any Registered Entity SME is familiar with the purpose and limitations of the protection systems that the entity will be able to demonstrate compliance. Suggested rewording of the Requirement: Each Transmission Operator, Balancing Authority, and Generator Operator responsible for the operation of BES elements shall have its operators be familiar with the purpose and limitations of protection system schemes, either through training or operational experience, applied in its area. There has been a broad variation in how the language of this requirement is applied during audits.
Individual
John Falsey
Invenergy LLC
Agree
Essential Power, LLC
Group
Pepco Holdings Inc. & Affiliates
David Thorne
Yes
No
PHI suggests the definition of Interconnection Element be revised as follows: “Interconnection Element: A BES element that electrically joins facilities a) owned by separate Registered Entities, or b) operated by separate Functional Entities (Distribution Provider, Generation Owner, or Transmission Owner) within the same Registered Entity.” Without this change the existing language could be mis-interpreted as requiring a documented Protection System Coordination Study on each and every internal BES transmission line (transmission line to transmission line coordination) within a Registered Entity’s system, just because the Registered Entity has registered as multiple Functional Entities, and despite the fact that all the lines in question are owned and operated by the same Transmission Owner Functional Entity. The intent of the standard is to address coordination of interconnected elements between separate Registered Entities or between separate functional entities within the same Registered Entity.
Yes
Yes
No
PHI finds that the revised wording in Section R4 does little to address the root problem associated with mandating mutual agreement. PHI suggests Requirement R4 be removed

entirely or extensively re-written to address the concerns outlined below: Requirement R4 is by far the most controversial aspect of this standard, particularly when mutual agreement between independent parties must be achieved. What if agreement cannot be reached, which entity would be held non-compliant? As currently written, the standard could lengthen schedules significantly for small projects. Consider for example the arrangement depicted in Figure 2 of the Application Guidelines. Suppose Transmission Owner S (T.O. S) initiates a Protective System change at Station 2 to raise the time dial of the back-up ground overcurrent relay on breaker D to maintain coordination with downstream relays. T.O. S performs the Protection Study and forwards the results to Generator Owner R (G.O. R). The study recommends that G.O. R must raise the time delay on breaker A to maintain coordination. Since breaker A is at the top of the coordination string, no other option may be available. Most likely the G.O. does not have protection engineers on staff and contract engineering support may be required to review the recommendation. As such, it could take several months for the engineering services to be acquired and the Protection Study reviewed. What if the G.O. is unwilling to increase clearing times for breaker A due to through fault concerns on the GSU transformer (even though the expected clearing times fall below ANSI transformer damage curves)? T.O. S is prohibited from making the change by R4.2 until agreement is reached. Which party is found non-compliant if an agreement cannot be reached? What if the change is not made because agreement could not be reached, and breaker D subsequently misoperates due the recognized miscoordination condition? A corrective action plan (per PRC-004) would be developed that would suggest the settings on breaker A be raised. Who would be found non-compliant if the corrective action plan was not enacted? 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.
Yes
Yes
1) The SDT states that "the requirements in the proposed Reliability Standard PRC-027-1 take

into account Recommendation 21 C of the Final Report on the August 14, 2003 Blackout in the United States and Canada written by the U.S.-Canada Power System Task Force, which identified the need to address the appropriate use of time delays in relays". However, a word search of the 2003 Blackout Report revealed no mention of miscoordination of time delays on relays during fault clearing as being a contributing factor. 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 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 Draft 1 of the standard. In their response 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) Requirement R2, Parts 2.1.1 and 2.1.2: Remove the term "interconnecting bus" and replace it with the phrase "point of interconnection between the Entities." The point of interconnection between the entities is more descriptive in that the interconnection point may not be a physical "bus", but rather the terminals of a line disconnect switch, terminals of a breaker, specific transmission pole, etc. Even though the point of interconnection is often modeled in a short circuit program as a "bus", the term "interconnecting bus" has no physical meaning. 4) Requirement R3, Part 3.3: A footnote should be added stating that this requirement does not apply to those temporary setting changes that sometimes are applied during commissioning, maintenance, or investigative testing activities to verify performance of individual protective elements, provided the original settings were returned upon the conclusion of the testing activity. For example, in multifunction relays when testing backup time delayed protective elements (i.e., zone distance or time overcurrent elements) it may be necessary to temporarily disable high speed elements (i.e., pilot or zone 1 elements). In response to this comment the SDT responded that it "believes temporary settings changes are addressed in TOP-002, which incorporated Requirements R5 and R6 from PRC-001-1. Temporary settings applied (or changed) to perform maintenance testing of a relay would not have an effect upon overall coordination of the Protection System, as the relay would likely be taken out of service for such testing." PHI agrees with this conclusion, however, this standard does not specifically exclude these temporary changes from Part 3.3. Therefore an auditor may conclude that they are in scope for this standard. As such, PHI suggests Part 3.3 be qualified with a footnote to specifically exclude these types of temporary settings. 5) Based on the commentary accompanying Figure 3 in the Guidelines and Technical Basis document it appears that a Protective System Coordination Study (PSCS) is required only if there are protective systems installed on breaker C for the purpose of detecting faults on the BES system. Is there a recommended criteria or generation size below which there is no need for a PSCS, or for a dedicated "fault protection system" at Breaker C to detect faults on the Interconnected BES element? For example, suppose all generation downstream of the Distribution Provider's system is comprised of solar installations with non-islandizing inverters. In these cases, it would be unusual to install fault detection systems "looking into" the BES system at breaker C even though there is generation installed downstream. The non-islanding inverters with 27/59 and 81O/U protection would isolate the generation upon loss of transmission source when Breakers A and B opened. Similarly, if a small synchronous generator was installed on a downstream distribution feeder with sufficient connected load to "swamp" the generator upon the loss of transmission source, protective relays at the generator location, rather than at Breaker C, would operate to remove the generator upon loss of the transmission system source. In both of these examples, even though there may be overcurrent protection, or fuses, installed on the high side of the transformer for transformer faults, there is no dedicated fault protection system installed at breaker C for the purpose of detecting faults on the transmission system, and as such there would be no need for a PSCS. Is this correct?
Individual

John Bee
Exelon and its Affiliates
No
ComEd believes that the definition should be revised to read “To coordinate time-delayed Protection Systems for Interconnected Elements, such that Protection System components operate in the desired sequence during Faults.”
Yes
No
We do not believe that a mandatory PSCS needs to be completed for each interconnected element as stated in Requirement 1. We believe that the design of the Protection System for an interconnected element must first be considered before requiring a PSCS. In cases where high speed protection schemes are redundant, the reliance on time-delayed backup elements would require at least 2 protection system element contingencies. We propose that redundancy should consist of the use of two separate relays and auxiliary relays as per the redundancy test required in the NERC board-approved TPL-001-2 standard. If failure of a single relay or auxiliary relay results in reliance on time delayed back-up protection, we agree that a PSCS should be required, and consequently would agree to the 60 month time frame.
No
This requirement unnecessary burden on the Generation Owner. The fault current seen by Generator Owner’s protective devices depend on the Generation Owners equipment (e.g., the main generator and transformers). So unless those are replaced there should be no requirement on the Generator Owner to review the protection coordination study due to change in fault current at the interconnecting bus which will be due to grid changes. The Transmission Owner will be reviewing those changes and will be coordinating if needed with the Generator Owner. Therefore these requirements should not be applicable to Generation Owner. [Requirement R1 1.1.2 and Requirement R 4 4.1 should also not be applicable to Generator Owner for same reason]. Need to identify which elements of Generator Owner’s protection system are included in this Standard and provide specific criteria for showing coordination with TOs protective devices.
Yes
Yes
Yes
a. For voltage levels at 345Kv and above (EHV), our standard Protection System design utilizes two high-speed pilot schemes, and includes time-delayed backup protection. Due to pilot scheme redundancy, the operation of time-delayed backup elements is an extremely rare event. Our time-delayed backup protection is intended to serve only as a safety net for

extreme events and we do not believe it is cost effective to study time coordination of these elements across our EHV systems. We believe that in cases where high speed protection schemes are redundant, that is designed such that loss of a single relay or auxiliary relay will not result in relying on time-delayed backup relaying to clear faults, the study of back-up element coordination is not necessary and the completion of a PSCS should not be required. b. Additionally, we believe Requirement 1 should state how many protection system failures must be considered for a PSCS. We believe that only one failure is appropriate for the reasons discussed above. c. PRC-001: The proposed Violation Severity Levels for PRC-001-3 R1 are not commensurate with the draft Measure of the Requirement. The current VSL is "High" for failure to be "familiar with the limitations of the protection system schemes applied in its area" and "Severe" for failure to be "familiar with the purpose of protection system schemes applied in its area." The draft Measure states that the applicable entity "shall have evidence that may include, but is not limited to, documentation indicating that training in basic relaying and any Special Protection Systems within its area was provided to its applicable personnel." The VSLs should be revised to align with the Measure and the "intent" of the Standard and not effectively split out the purpose of Requirement R1 thus requiring specific documentation for a "purpose" and a "limitation". Exelon suggests the VSLs be revised to the following: Severe: The responsible entity failed to provide evidence that any training evidence exists for basic relaying and any Special Protection Systems within its area. High: The responsible entity failed to provide evidence that all applicable personnel were trained in basic relaying and any Special Protection Systems within its area d. PRC-001: In the Background Section of PRC-027-1 there is a discussion related to PRC-001-1 that was revised as part of Project 2007-03. Specifically, it is stated that in Project 2007-03 SDT retired PRC-001-1 Requirement R2 as because this Requirement addresses data and data requirements that are included in the proposed Reliability Standard TOP-003-2; however, the justification provided in the mapping document associated with Project 2007-03 does not seem to meet the original intent of PRC-001 R2, and does not seem to be a "relocation" of the original requirement (refer to Project 2007-03 Mapping Document Draft 7). PRC-001-1 R2 current revision is as follows: R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows: R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible. R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible. The Background Section of PRC-027-1 further states that the SPC SDT recommends that Requirement R1 remain in PRC-001-2, until its reliability objective is addressed by either a revision to an existing standard or development of a new Standard. The current revision to PRC-001-2 that removed Requirement R2 was not fully addressed by Project 2007-3 nor voted on by the Ballot Body and therefore Exelon requests that PRC-001-1 R2 be added back in to PRC-001-3 and Project 2007-06, similar to Requirement R1, until its reliability objective by similarly addressed by either a revision or development of a new Standard.
Individual

Nazra Gladu
Manitoba Hydro
Yes
Yes
(1) For clarity, consider re-writing the definition as “A BES Element that electrically joins a Facility owned by: a) a separate Registered Entity, or b) the same Registered Entity that is represented by multiple functional entities (Distribution Provider, Generator Owner, or Transmission Owner).”
Yes
Yes
Yes
Yes
(1) The title of the new PRC-001-3 standard does not seem to be the appropriate title since the standard addresses protection coordination issues, rather than requiring the system operators to be familiar with, and understand the protection system.
Yes
(1) The wordings of the sentence “Examples of Protection Systems where technical justifications may be used include” under heading “Requirement R2 in the “Application Guidelines” are unclear. MH suggests that It read as follows: “Examples of Protection Systems that are not affected by the fault current change include”. Also, under the same section, it’s very confusing as to what relays the following refers to: 4. Reverse power, definite time &/or time overcurrent elements: Designed to coordinate during maximum generation with the transmission system under normal operating conditions and includes the calculation of the percent deviation between the under single contingency conditions regardless of Fault current. Designed for the protection of equipment other than for the purpose of detecting Faults on BES Elements even though those relays that may operate for such Faults, but are not installed specifically for that purpose (i.e. transformer overcurrent, reverse power, etc.). (2) Protection System Coordination Study definition - for clarity, replace the word “that” with the word “which” and insert the word “that” between “demonstrates existing”. Moreover, consider replacing the words “for clearing Faults” with “during Faults” for consistency with the purpose of the Standard. The suggested definition should read “A study which demonstrates that existing or proposed Protection Systems operate in the desired sequence during Faults. This definition should also be changed in the rational for R1 section and Implementation Plan document if it is an accepted change by the SDT. (3) Background - references are made to standards PRC-001, PRC-027, TOP-003, PRC-005, etc. in this section, which in some cases, do

not include the title following the standard number. For consistency, the title should be included, or in the least referred to at the first instance of the standard number in this section. (4) Other Aspects of Coordination of Protection Systems Addressed by Other Projects - replace the period "." at the end of the last paragraph with a colon ":" . Moreover, follow each project number with its title for consistency and clarity. (5) R1.2 - the words "Protection Systems" and 'Currents used" should be written as "Protection System(s)" and "Current(s) used" to maintain consistency with the rest of the paragraph. As a note, consider changing all instances of the words "Protection Systems", "Currents", "owners" and "Interconnected Elements" to "Protection System(s)", "Current(s)", "owner(s)" and "Interconnected Element(s)", to maintain consistency throughout the document. (6) R2.1 - remove the words "Protection System Coordination Study", leaving only the acronym "PSCS", because it has been previously defined in the document. (7) R2.2.1 and M5 - add an "s" or "(s)" to both "Protection System" and "Interconnected Element". (8) M4 - replace "is" with "includes" and "that contains" with "which contain". (9) All measures - for consistency, the phrase "may include, but is not limited to," should be added to each measure. (10) R4.2 - place brackets around the "s" in the following words "modifications" and "issues" for consistency with the rest of the document. Please continue this change throughout the Standard and Technical Guideline document for consistency. (11) 1.2 Evidence Retention - is it necessary to state that "The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit." since this information is already included in the CMEP. (12) R4.2 and M10 - the words "proposed changes and modifications" should be changed to "proposed changes and additions" to mirror the wording in R3.1.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the revised purpose statement, but reiterate our previous suggestion to add "settings" after protection system (with the "s" removed") to make it clear that it is the coordination of the settings, not the design of protection systems. The SDT's response to our previous comment indicates that: "…settings' are not the only aspect of Protection Systems that can impact the stated purpose." We are unable to come up with any specific examples of what other parameters or actions associated with the Protection System of an Interconnection Element that would require coordination to ensure "Protection System components operate in the desired sequence during Faults". Please elaborate, or revise the purpose statement accordingly.
Yes
Yes

Yes
Yes
No
We do not have any comment on the revised Applicability Section, but continue to express a serious concern with leaving PRC-001 in its present form. As indicated in our previous comment, we do not agree with the proposed PRC-001-3 for the following reasons: a. The purpose statement is inappropriate as the standard now does not address Protection System coordination among operating entities. b. Requirement R1, as written, is not measurable and should be rescinded. This is a training requirement and as such, it should be transferred to the appropriate PER standards. Providing training evidence does not demonstrate that the (operating personnel of) responsible entities are “familiar with” the purpose and limitations of protection system schemes applied in its area. c. The SDT holds the position that Requirement R1 belongs to another project and thus has proposed that R1 remain in PRC-001-2 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. In response to our previous comment, the SDT indicates that it “…recommended that Requirement R1 remain in PRC-001-3 until its reliability objective is addressed by either a revision to an existing standard or development of a new standard. This issue has been added to the NERC Issues Database.” We do not agree with this recommendation and hold the view that adding the issue to the NERC Issue Data Base is an incomplete and perhaps irresponsible move given the SDT is assigned the task to change or transform PRC-001 into a revised or new standard. At a minimum, the SDT should propose a revision to the SAR or this project to expand the scope and identify the appropriate PER standard which can be a home for Requirement R1, and made the appropriate wording change accordingly. Having a new PRC-027-1 standard to house some of the PRC-001-2 standard but not finding a home for the remaining R1 does not help reliability. We urge the SDT to propose a revision to the SAR, or seek the Standards Committee’s advice/direction for appropriate actions. We do not believe that the SDT or staff has brought this to the Standards Committee’s attention. Note that the Standards Committee is responsible for managing the standards development process and as such, can make an informed decision to either request the SDT to expand its scope (via an amended SAR) to address the PRC-001 issue, or to ask staff or the SDT to prepare a separate SAR to address the issue in parallel. Leaving the PRC-001 hanging out there without a recourse is not a satisfactory solution, and may in fact harm reliability. Once again, we urge the SDT to take the initiative to bring this issue to the Standards Committee, with a proposal to amend the SAR or prepare a new SAR, or seek its advice and direction before continuing work on this project.
No
We do not agree with the proposed Measure for the reason as stated under Q6, above.
Group

Duke Energy
Michael Lowman
Yes
Yes
Yes
Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Yes
Duke Energy agrees with the changes made by the SDT to extend the period to 60 months.
Yes
Yes
Duke Energy believes that the Facilities section provides sufficient detail and clarity for this standard.
Yes
In the interest of clarity, Duke Energy feels an example of acceptable evidence for measure 3 of PRC-027-1 R2 would be beneficial. In PRC-027-1, Duke Energy identified a potential gap in Figure 4 of the Application Guidelines. Duke Energy believes that without coordination between the DP and TO, it could lead Transmission Planners and System Protection Engineers to disregard the coordination with protection for the tap line between BES and non-BES equipment. Given the proposed definition of the BES, this scenario could potentially pose a risk to the BES without the proper coordination identified in PRC-027-1.
Individual
NICOLE BUCKMAN
ATLANTIC CITY ELECTRIC COMPANY
Agree
Pepco Holdings Inc. and Affiliates
Individual
Don Schmit
Nebraska Public Power District
No
Will there be an expectation that each entity involved with interconnected elements or facilities be pre-identified in any other documentation other than perhaps in each PSCS?

No
In theory I understand the drafting team stating: "The drafting team believes that any conflict resolution should be handled through normal business practices. The old Measure M9 (new Measure M10) has been modified as follows: Acceptable evidence for Requirement R4, Part 4.2 is dated documentation (hardcopy or electronic file formats) demonstrating that, prior to implementation of any proposed Protection System(s) changes, communications (e.g. email acknowledgements) of those changes were completed, and any identified coordination issues were resolved and accepted. The drafting team believes the requestor cannot be held accountable when the other party does not respond". However, I don't believe that we can predict or project how an audit or enforcement team will apply or misapply this requirement which is cause for concern. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. Perhaps some form of clarification could be added to the application guidelines or another location for example.
My general impression is this standard could be quite a burden to track data for an audit due to the numerous time lines specified that are between entities. My opinion is this will likely result in a difficult to audit standard. This causes concern if we remain in a zero tolerance compliance environment. Consider changing some of the time lines such as 30 and 90 days to 6 months. My general feeling is we should consider other ways to simplify this standard however suggestions I have made have not made it into the draft standard. I recommend more consideration be given to simplification.
Individual
Michael Mayer
Delmarva Power & Light Company
Agree
Ppeco Holdings Inc. and Affiliates
Individual
Mark Yerger
Potomac Electric Power Company
Agree
Pepco Holdings Inc, and Affiliates
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration ("ICLP")agrees that the updated purpose statement is more appropriate for a BES Reliability Standard. The previous version sought to minimize the faulted

elements – which is a desirable goal in most cases, but may not be the highest priority where multiple interconnected entities are concerned. (Otherwise, the ironic result could be that local service is preserved at the expense of the wider-area system.) The intended Protection System design should predominate, as it will account for any such circumstances.
Yes
The addition of the modifier “BES” to describe the applicable Elements is critical in Ingleside’s view. Without it, CEAs may assume that a Fault study is required for an interconnection at any voltage – an issue highlighted in FERC Order 773 concerning the Definition of the BES.
No
ICLP mostly agrees with rationale for R1 that states “The drafting team has no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements that warrants a shorter time frame <than 60 months>.” We would take that one step further and argue that far more critical coordination occurs in UVLS, UFLS, SPS, and distance relay schemes – and is already covered in other NERC standards. Fault analyses are comparatively basic, and do not require a re-evaluation unless a material change is made in the local grid. This means that a Generator Owner should be able to make a simple confirmation that nothing has changed since the previous time a Fault study was performed – usually during commissioning or a major reconfiguration. If the TO wants a full Fault evaluation due to a change in the local transmission system, they are free to do so under R1.1.2. Requiring every GO to produce the results of a study that took place years in the past serves no reliability purpose.
No
Although ICLP is not a Transmission Owner, we will be impacted if the TO’s assessment shows a material change in Fault current has occurred in an interconnecting element. We believe our TO has every economic and reliability incentive to contact us if a modification threatens the transmission network. It should be sufficient that the TO show that a coordinated assessment takes place when an appropriate trigger condition occurs.
Yes
Yes
ICLP agrees that consistency between NERC standards is helpful. Since our Protection System maintenance program has been developed specifically to address BES relaying, it is a straight forward process to develop the related Operator training.
No
ICLP believes that the measure should identify that front-line operators are the target audience of the training. As a Generator Operator, we employ engineers, process developers, and operators – and not all of these individuals require basic Protection System training. This ambiguity should be resolved while there is focus on PRC-001.
Individual
Don Jones
Texas Reliability Entity

No
We suggest re-wording the second half of the purpose to say "such that Protection System components operate in the desired sequence to properly isolate Faults".
No
We have concerns with this proposed definition surrounding the current state of the proposed BES definition changes especially in light of the multiple possible exclusions that may be allowed. In ERCOT, there are numerous large private-use-networks (PUNs) with generation behind the fence that could possibly be excluded under the new BES definition, based solely on how much power they export to the grid. If the new definition of the BES grants exclusions to these PUNs, then the PUN as well as the Transmission Owner that connects to the PUN would not be subject to the requirements of PRC-027. In our opinion, this presents a risk to the BES in that there could possibly be protection systems associated with the PUN interconnection that might need to be coordinated to properly respond to faults on the BES or within the PUN. These protection systems should require some level of coordination between the entities involved.
Yes
Yes
Yes
Yes
Yes
How many buses away from the Interconnect Element does the PSCS need to cover? Figure 5 of the Application Guidelines indicates that only the next adjacent bus is to be included in the PSCS, which implies that the PSCS only covers up to Zone 2. We understand that PRC-027 does not tell any owner how to perform a PSCS or dictate the specific information that is required for a PSCS. It appears from our understanding that the coordination of protective relays beyond the primary zones that affect the interconnected element are the responsibility of the equipment owner, and that it is up to the owner to determine whether these settings are to be shared with other entities for the interconnected element. Please clarify if this understanding is correct.
Individual
Thomas Foltz
American Electric Power
Yes

Yes
The term “functional entity” is defined in the NERC Glossary of terms and we believe it should be capitalized in this definition.
Yes
Yes
Yes
No
AEP appreciates the drafting team’s efforts to clearly identify the Protection Systems that are applicable to Requirement R1 but is concerned that the combination of Applicable Facilities in Section 4.2 and Requirement R1 may result in burdensome training requirements for the TOP, BA and GOP that do not provide an increase to BES reliability. In particular, the Applicable Facilities includes Protection Systems installed for the Generator Step-Up transformers, Station Service transformers and the Excitation transformers. Nowhere does the standard limit the scope of this applicability to a subset of the Applicable Functional Entities. As a result, an auditor may interpret the standard to require that the TOP and BA be familiar with this level of generator protection for the units connected to their system.
No
The examples of evidence in Measure M1 appear to be overly simplistic compared to the potential scope of R1.
PRC-001-3: R1 – The term “protection system” should be capitalized to match previous versions of this standard. PRC-027-1: Mapping Document – The verbiage in R1.1 of the mapping document does not match the wording in the proposed standard: “Protection System Study” is used instead of “PSCS”. PRC-027-1: Figure 2 – The phrase “generator Protection Systems” is often used by Generation Owner relay engineers to mean the Protection Systems installed for the purpose of detecting faults on and protecting the physical generator, which is clearly outside of the scope of this standard. Therefore, AEP recommends changing the verbiage associated with this figure to remove the phrase “generator Protection Systems” and replace it with a reference to Generator Owner R’s Protection Systems installed for the purpose of detecting faults on the Interconnected Elements. Suggested wording is shown below: Transmission Owner S is to review the Protection System settings associated with Breaker A *and the Interconnected Element* (provided by Owner R) for coordination issues with the Protection System settings associated with Breakers C, D, E, and F. Likewise, Owner S is to develop proposed Protection System settings associated with Breaker C. Generation Owner R is to review the Protection System settings associated with Breaker C *and the Interconnected Element* (provided by Owner S) for coordination issues with the Protection System settings associated with Breaker A. PRC-027-1: R3 & Figure 5 – As written, R3 will place undue burden on each TO, GO and DP to maintain a list of all other entities connected to each

interconnecting bus to which they connect. Furthermore, since the elements are typically owned by the TO, burden will be placed on the TO to respond to requests from other TO's, GO's and DP's as they build their list. R3 and its' associated Figure 5 should be revised such that the responsibility lies with the owner of the Interconnected Element to ensure that relevant information is passed along to each entity who connects to the element when any one entity makes a change.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Yes
Yes
Yes
We agree with Part 4.1 of Requirement 4, but we have comments regarding Part 4.2 and have stated below in Question 8.
Yes
Yes
Although we agree with the proposed change, we have reservations of having a standard with only 1 requirement. Please see our comments on Question #8.
In regard to PRC-027-1: We believe that R3, Part 3.1 is covered in R1, Part 1.2 and propose that R4, part 4.2 be reworded to: 4.2. Prior to implementing any proposed change (s) or modifications associated with 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 In regard to PRC-001-3: The title for PRC-001 "System Protection Coordination" and the purpose statement of this standard is no longer pertinent for the only requirement that remains in the standard - entity familiarity with the purpose and limitations of protection system schemes. This remaining requirement is essentially a training obligation and better suited in a PER standard if deemed necessary for reliability. The drafting team also appears to support this view as discussed in the background statements of the PRC-027-1 standard, however, believes this additional work is outside the scope of its project. However, the PRC-001-3 standard should not be left with a title and purpose statement that will cause industry confusion with PRC-027-1. We suggest that this team adjust PRC-001-3 to include the title "System Protection

Awareness" and a purpose statement of "To ensure entity understanding of system protection schemes applied to their assets." FE believes the continuing need for this requirement (PRC-001-3 R1) needs to be carefully considered. NERC standards PRC-023 and PRC-25 address relay loadability limitations. The original blackout report recommendation that drove this requirement appears to now be more thoroughly addressed by those standards. We encourage the NERC Standards Committee to extend the scope of this drafting team's work through a supplemental SAR to address whether or not PRC-001 can be retired.
Individual
Michael Moltane
ITC
Yes
No
The Applicability section 4.2 defines "facilities" as protection systems with the purpose of detecting BES faults on Interconnected Elements. Therefore, in example Figure 4 the DP does not own "facilities" and the transmission line or tap are not an Interconnected Element. The definition of Interconnected Element should reflect this fact and Figure 4 should be corrected. If the intention is that Figure 4 should be an Interconnected Element so that R2 still applies, then clarification that Interconnected Elements does not require Applicability section 4.2 defined facilities is required. ITC Holdings engineers perform coordination at Interconnected Elements between ITC Holdings subsidiaries ITCTransmission and METC, both registered TOs. The definition should exclude applications such as this, where the only outcome is increased administrative burden to be auditable with no reliability benefit to BES.
Yes
Yes
Yes
Yes
ITC Holding is in agreement with the clarification on which protection systems are applicable to requirement 1. Using the same definition as used in PRC-005-2 promotes consistency across the standards within the same category (PRC).
Yes
ITC Holdings is in agreement to add the measure to the standard to be in-line with the language in the RSAW for PRC-001-2.
We vote to reject Draft 3 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 4 exclusion of PSCS on the Interconnected Element is not found in standard. Figure 4 states the line or tap is the Interconnected Element, therefore TO owns "facilities" and must meet R1-R4. Either definition of Interconnected Element must be revised to exclude Figure 4 example, or Figure 4 must be corrected to show TO is still responsible for R1-R4. Example Figures 1-5 create responsibilities on owners to "propose" and "review for coordination" which are not found in the standard. Either these responsibilities should be removed from Figures or the responsibilities should be added to the standard. The last sentence in Figure 5 specifies the TO will provide GO settings to the other TO. This contradicts R3 which states, "Each TO, GO, and DP shall provide to each TO, GO, and DP…" Again, the Figures are creating responsibilities not found in the standard. The purpose of Applicability section 4.2 Facilities is unclear. Each requirement deals with requirements around the Interconnected Elements. If the purpose of section 4.2 is to try and exclude DP relays which do not purposefuly trip for BES faults, this should be more clearly stated. This exclusion should be moved to Interconnected Element definition and section 4.2 rewritten to target Interconnected Elements. Or section 4.2 should be the corrected Interconnected Element definition, and there will be no need for a new definition in this standard. Example Figure 2 creates different responsibilities for GO than Figure 3 does for DP. Why the difference? Essentially they are the same: both have protection systems which trip for faults on Interconnected Element. Again, the Figures are creating responsibilities not found in the standard.
Individual
John Seelke
Public Service Enterprise Group
No
As a Results-Based Standard, "coordinate" should be removed from the Purpose. We suggest that the Purpose should be "To ensure that Protection Systems involving Interconnected Elements operate in the desired sequence during Faults."
Yes
Yes
No
We agree with that the 60 months is adequate; however, we disagree that a technical justification should be required for relays and schemes that are unaffected by the level of Fault current. See our proposed language changes in 8.a below.
Yes

No
Change section 4.2.1 (capitalized words show changes) as follows: “4.2.1 - Protection Systems that are installed for the purpose of detecting AND ISOLATING Faults on BES Elements (lines, buses, transformers, etc.)”
No
• Requirement R1 requires that “Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.” This is too broad and vague with respect to which TOP, BA and GOP personnel are in the requirement’s scope. Subject to addressing PSEG’s additional comment of “What is meant by “familiar with” in R1?” in the bullet below, PSEG recommends that the requirement at least be revised to: ”Transmission Operator, Balancing Authority, and Generator Operator personnel shall be familiar with the basic purpose and limitations of protection system schemes applied to the BES equipment and Facilities they control.” • M1 should describe methods other than documented training to meet R1 – see the “but not limited to” language. What is an alternative to documented training? What is meant by “familiar with” in R1? Until “familiar with” is better defined, M1 cannot be written.
PSEG has the following additional comments: a. To avoid make-work reporting that is detrimental to BES reliability, PSEG recommends that the Applicability section remove Protection Systems, Interconnected Elements, and Protection System components that do not require coordination. Therefore, we propose that the 4.2.1 be modified with this additional language after “faulted Element”: “, except for the following Protection Systems, Interconnected Elements, and Protection System components that do not require such coordination: • Protection Systems for the Interconnected Element that are owned by the same functional entity of a single Registered Entity. • An Interconnected Element that is protected by overlapping differential relays only (e.g., a Generator Owner’s GSU that is connected to a Transmission Owner’s bus) • Protection System components for which coordination is unaffected solely due to an increase in Fault current, including: • Transformer differential relays • Line current differential schemes • Generator differential or overall differential, bus differential schemes • Step distance protection schemes • Fault detector settings (these settings are guided directly by PRC-023-X) • Breaker failure settings • Directional Comparison Blocking overcurrent schemes b. “Application Guidelines” comments 1. More clarity on what a pre-standard PSCS needs to contain to meet R1.1. Is an e-mail trail from other owners stating that the settings are acceptable? Do calculations need to be shown? 2. Language on p. 21: “The drafting team also has no evidence there is widespread miscoordination between owners of Facilities associated with Interconnected Elements that might warrant a shorter time frame for the studies to be performed. Protection Systems are continually challenged by Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” If there is no problem, why is this standard being proposed? 3. Language on p. 22 that lists examples of Protections Systems where technical justification may be used to exclude the need for a PSCS. Although PSEG has suggested limiting the Applicability in its comments in 8.a, it may be simpler if the standard just listed the Protection Systems that require a PSCS – that would only be overcurrent elements based upon Fault current. If that

scheme is not employed, no PSCS is needed.
Individual
Andrew Z. Pusztai
American Transmission Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Jonathan Meyer
Idaho Power Co.
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Thank you for the opportunity to comment. While we are in favor of this version, we seek clarification on one item. Requirement R2 states that the fault values used in determining the 10% change will be measured at the “interconnecting bus”. While reviewing the examples in the application guideline section, two “interconnecting bus” are labeled in Figure 1, 3, and 4. If the coordination concern is related to the interconnecting element, it would seem reasonable that the “interconnecting bus” for Owner S to place faults on to determine the 10% change is that at Station 1/Transmission owner R, looking at figure 1. This would capture the change in fault current seen by the Owner S Protection System on breaker E. Placing faults on the interconnecting bus behind breaker E if I am owner S does not seem appropriate when considering coordination on the interconnecting element.
Group
Bonneville Power Administration
Morgan Senkal
Yes
No
1. In this new term, the use of “interconnected” implies that the element is connected by another element, which is not what is intended. A more appropriate word would be “interconnecting” as this indicates that this is the element that connects other elements. 2. The definition as written does not make sense because there is typically not an element that electrically joins facilities owned by separate registered entities. Instead, where the point of interconnection between separate registered entities is made, one entity will own the element on one side of the point of interconnection and the other entity will own the element on the other side of the point of interconnection. The change of ownership is made at a point, not through a commonly-owned element. Since all elements are owned by one entity or the other, there is no element that electrically joins the elements owned by the two entities and nothing that meets the definition provided for an Interconnected Element. 3. Part B of the definition does not indicate which element is the Interconnected Element in a system where the same registered entity represents multiple functions. Does this allow the entity to choose which element is considered to be the Interconnected Element? For example, if an entity is both a generator owner and transmission owner they will own all elements from the generator to and including the transmission system, with no change of ownership. There is no clear point where the generator function stops and the transmission function begins. Which element will be considered to be the Interconnected Element and required to comply with this standard?
No
BPA believes that the requirement to provide a protection system study for each interconnected element is onerous, and as a result, any amount of time is too short. While beneficial to periodically perform fault studies and review protection system coordination, the creation of a NERC standard to require reviews for Interconnected Elements on a rigid time

frame is likely to be counterproductive for the following reasons: a. There is nothing unique about the Protection Systems for Interconnected Elements compared to other Protection Systems that warrants this special treatment. If this standard is deemed necessary, the only logical consequence is that similar standards must be created for all protection systems. Trying to coordinate Protection Systems to comply with numerous standards will limit flexibility. Diverting resources from addressing Protection System problems to completing compliance documentation makes the system less reliable, not more. b. This standard provides no quality benefit to the Protection System Coordination process. It only increases the documentation burden, which is just as likely to decrease the quality of the review as it is to improve it. c. There are an enormous number of things that entities do to keep the BES reliable. If NERC wishes to regulate and enforce all of these things, it will come at an enormous cost to consumers of electric power. Cost increases are already being experienced due to the present standards. Since there has been no widespread problem with Protection System coordination between entities, this particular issue should not be the subject of a standard. d. Any specified time frame for a Protection System Coordination review will be too long for some situations and too short for others. The Protection System Engineers within the entities are in the best position to determine an appropriate review interval for each element.
No
Please see comments for Question 3.
No
The requirement does not describe what further actions are required or what time limits apply if the suggested modifications are not acceptable to the originating entity.
No
As described in the Facilities Section, the protection systems for which the requirements are applicable are “Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements”. Since most Protection Systems are capable of isolating faulted elements without coordination, nearly all Protection Systems would be exempt from the requirements. While this would be acceptable to us, we don’t think this is what the drafting team intends.
Yes
1. The definition of Protection System Coordination Study is inadequate because it does not address what type of faults must be studied or where on the system the faults need to be applied. 2. R1.1.2 uses the term interconnecting bus. This is not a common term and requires a definition.
Group
PacifiCorp
Ryan Millard
Yes

Yes
Yes
Yes
Yes
Yes
PacifiCorp would like to highlight a recommendation that was made by the drafting team on page 4 of Draft 3 of PRC-027-1 regarding Requirement R1 of PRC-001-2. The drafting team has recommended via the NERC Issues Database that the future standards drafting team tasked with revising PER-005-1 incorporate the reliability objective of PRC-001-2 Requirement R1 into that revised standard. PacifiCorp is concerned with the potential overlap that could result from the failure to retire Requirement R1 in PRC-001-2 concurrent with the effective date of the new version of PER-005. To avoid the risk of entities having to comply with duplicative requirements under two currently-effective standards, the standards drafting team should include language in PRC-001-2 expressly confirming that compliance with the relevant requirement of the revised version of PER-005 will satisfy Requirement R1 of PRC-001-2 until such requirement is retired. In addition, there have been several proposals in the informal development of PER-005-1 that would expand the scope of applicability to include Generator Operators and Support Personnel. If R1 of PRC-001-2 is to be included in the new version of PER-005-1, the requirements of R1 could apply to additional functional entities. As such, any recommendation to move R1 of PRC-001-2 into the new version of PER-005-1 should be part of the PER-005-1 discussions that are currently taking place. At present, they are not. PacifiCorp would like to encourage more collaboration between drafting teams on the development of new draft standards and would like to thank the System Protection Coordination Standard Drafting Team for highlighting this recommendation.
Yes
Individual
Bill Middaugh
Tri-State G &T
Yes
Yes
Yes

Yes
Yes
Yes
No
Tri-State believes that the Requirement R1 and Measure M1 need to refer more directly to the Facilities included in the Applicability section. A couple of options are presented below. Option 1: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of the following protection system schemes applied in its area: • Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.) • Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements. • Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability. • Protection Systems installed as a Special Protection System (SPS) for BES reliability. • Protection Systems for generator Facilities that are part of the BES, including: o Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays. o Protection Systems for generator step-up transformers for generators that are part of the BES. o Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES). o Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays. If Option 1 is chosen, then the Facilities section in the Applicability can be removed. Option 2: M1. For Requirement 1, each Transmission Operator, Balancing Authority, and Generator Operator shall have evidence that may include, but is not limited to, documentation indicating that training in the purpose and limitations of the Protection System schemes included in the Facilities section of the Applicability that are used within its area was provided to its applicable personnel.
Tri-State is concerned about the timeframes allowed in Requirement R1, associated with Requirement 3, Part 3.1, especially when the proposed change does not affect the conditions used in the coordination of Protection Systems. The way we read Requirement R3, Part 3.1, a planned relay replacement will have to go through the PSCS process or a technical justification would be required even if it does not affect coordination of other Protection Systems. We would propose that Part 3.1 be changed as follows: 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element if the proposed change requires a change in the coordination of Protection Systems associated with the Interconnected Element(s); or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s).

Individual
Kayleigh Wilkerson
Lincoln Electric System
In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has “no evidence there is widespread miscoordination of Protection Systems associated with Interconnected Elements”, LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard’s development. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, LES suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination.
Individual
Karen Webb
City of Tallahassee - Electric Utility
Agree
Florida Municipal Power Agency (FMPA)
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Individual
Bill Fowler
City of Tallahassee
Agree
FMPA
Individual
Scott Langston
City of Tallahassee
Agree
FMPA
Group
Dominion
Randi Heise
Yes
1) The SPC standard drafting team created this result-based standard specifically directed toward Interconnected Facility applications by stating in the current draft that “PRC027-1, with the stated pupose ‘to coordinate Protection Systems for Interconnected Elements….’ . Also in Draft#3 the purpose now places emphasis on “desired operating sequence” versus Element isolation. To align with this purpose, as previously suggested, we recommend that the title of this standard reflect the revised purpose and be renamed “Protection System Coordination for Interconnected Elements”.
Yes
1). The word “facilities” included in the proposed definition, “Interconnected Element: A BES Element that electrically joins facilities owned by…” should be capitalized as it is included in NERC’s Glossary of Terms Used in NERC Reliability Standards. 2). Dominion agrees with SERC PCS comment: “As evident by a note in the rational box for R1 (Page 6 of Redline Version) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.”
Yes

Yes
Yes
Yes
Yes
Dominion believes the reference to PRC-001-2 is incorrect and should be noted as PRC-001-3 as PRC-001-2, Page 11, cites “Measures and Compliance Elements will be added to a later draft.” Dominion supports the measure accompanying Requirement 1, as included in PRC-001-3. Dominion also notes that the reference to the RSAW for PRC-001-2 is incorrect and should reference the RSAW for PRC-001-1. Dominon was unable to locate a draft of RSAW PRC-001-2 or PRC-001-3 on the Standards Under Development NERC webpage or under any category, on the NERC RSAW page.
1). Under Requirement 2 (Page 8 of Redline Version), studies are referred to as “most recent” and “present” which is confusing and could be considered synonymous. Recommend changing this terminology to replace “most recent” with “previous” study and “present” with “new” study in all places within the standard where they exist. 2). Requirement R3, 3.1 first bullet (Page 10 of Redline Version) is both broad far reaching (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications CT/PT ratios). 3.1 Clearing targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. Recommend changing bullets to clarify areas of this emphasis to: • Change in Protective Relay Types or Functions • Change in Communication System(s) that interface with Protection System(s) • Change in connected voltage (VT) or current (CT) source ratios • Change to transmission system Element(s) that alters impedance • Change to generator unit (s) that alters impedance • Change to generator step-up transformer (s) that alter in impedance 3). In Application Guidelines – Example Process (Page 30 of Redline Version) the second bullet indicates that a single study can be used whereas in R1 1.1.3 it states that “each” entity shall perform a PSCS. Recommend clarification in this example to reflect Note that is included in Rational for R1 that indicates in cases where a single group performs overall study for the interconnection for both entities. This reference may lead to confusion in the example. 4). Wording is confusing in PRC-027-1 Applicability Section (Page 3 of Redline Version). Suggest combining 4.2 and 4.2.1 into something like “Protection Systems owned by the Functional Entities in 4.1 are applicable if they are installed for the purpose of detecting Faults on Interconnected Elements of the BES and require coordination for isolating those faulted Elements”. 5). There are numerous locations in the standard that note that “Protection System Coordination Studies are typically performed assuming maximum generation and all Facilities in service.” Given the complexities of system configurations, it is not always the case that this scenario (Max Gen and All Facilities In) will be the best case under which to verify proper coordination. Recommend removing this note and require entities to determine the best scenario under which to evaluate coordination.

The presence of this note may create unintended bias. 6). Dominion agrees with SERC PCS comment: “Please change Figures 3 and 4 in the Applications Guidelines section so that “Interconnected Element” is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the “Interconnected Element”.)
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
In our area, there do not appear to be any issues with lack of protection system coordination and I am unsure if there is really a need for this standard. Their appear to be adequate protection systems standards noted in the "Other Aspects of Coordination of Protection Systems Addressed by Other Projects" section.
No
It is difficult to support the current definition that relies on the BES Element language from the BES definition process that has not been finalized. In our case, there are elements that would not be in scope for Interconnected Element consideration, but if there is no finalization of the BES definition and this standard moves ahead, the heart of this definition would be in flux. More specificity in what equipment we are really talking about here might be helpful in the absense of a settled definition of a BES element.
Yes
Yes
No
Although well-intended, this seems like a difficult thing to document for audit if there are legitimate back and forth over a long period of time.
No
Do not believe that a DP-only entity would typically have Interconnected Elements that would necessitate inclusion, when the purpose is to protect the TO equipment.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No

Change "in the desired sequence" to "in an acceptable sequence". This better reflects the compromises that may be required by the different entities owning protection systems on an Interconnected Element.
Yes
No
Requirement 3.3 needs to be revised to allow an entity the flexibility to make emergency changes to protection systems or settings that are necessary to correct a reliability problem. The current draft allows such changes only when a failure occurs.
Yes
No
R4 needs revision to better accomodate the entire range of diversities in TO-GO interconnections, especially when agreement cannot be reached between entities, or when agreement cannot be reached in a timeframe required to make critical changes during generating unit outages. R4 also neeeds to include flexibility when the GO is not a vertically integrated utility, and does not have in-house protection engineering resources to respond in the required timeframe. It is unjust to put compliance risk on an entity due to the failure of another entity to reach agreement on settings. In some cases the best that can be expected is for two parties to exchange protection system information and live with a compromise in coordination that allows both to best protect their assets. This may be especially true when generating assets are at stake, and insurance considerations require sensitive protection that may not allow complete coordination.
Individual
Richard Vine
California ISO
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
See associated SRC Comments
The ISO feels that a requirement should be added for the TO, GO or DP to notify their TOP and PC when a new or revised Remedial Action Scheme or Special Protection System is implemented.

Group
PJM Interconnection
Stephanie Monzon
Yes
Yes
Yes
Yes
PJM supports both standards as drafted. Specific to PRC-001-3 R1, PJM urges the SDT to replace the term ‘familiar’ with language less subjective. There may be a number of interpretations for this term that will result in compliance issues for applicable entities. Suggested revised wording should include language that has a direct tie to the Measure. PJM recommends the following revised requirement for the applicable entities, ‘knowledge of the purpose of and limitations of protection system schemes shall be based on the training programs provided.’
Individual
David Jendras
Ameren
Yes
(1) Ameren supports the SERC Protection & Control Subcommittee comments and hereby includes them by reference rather than repeating them all.
Yes
(1) The word “facilities” should be capitalized, since it is included in the NERC Glossary: “Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)” and “Element - Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.”
Yes
Yes

(1) The "maximum available Fault current values (single line to ground and 3-phase) at the interconnecting bus" could either be the total Fault current at that bus, or the Fault current flowing through the Interconnected Element. Our reading of R2, Part 2.2 "used in the most recent PSCS" is that it depends on what the entity used in their study.
Yes
Yes
Yes
(1) The measure was provided for PRC-001-3, not PRC-001-2.
(1) In Application Guidelines for R1, please add “A Protection System Coordination Study includes, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed.” We request adding it just after the definition of a PSCS. This will more clearly align the Application Guidance with R1.2. (2) Under Requirement 2, studies are referred to as “most recent” and “present” which is confusing and could be considered synonymous. We ask the SDT to change this terminology to replace “most recent” with “previous” study and “present” with “new” study in all places within the standard where they exist. (3) Requirement R3, 3.1 first bullet is both broad (new installation, replacement with different types) and specific (modifications to protective relays or protection functions settings, communications, CT/PT ratios). The 3.1 text itself clearly targets changes or additions to existing or new Facilities that modify conditions that impact coordination of Protection Systems. We request the SDT to replace the existing bullet points to clarify areas of this emphasis to these bullet points: “• Change in Protective Relay Types or Functions • Change in Communication System(s) that interface with Protection System(s) • Change in connected voltage (VT) or current (CT) source ratios • Change to transmission system Element(s) that alters impedance • Change to generator unit (s) that alters impedance, or • Change to generator step-up transformer (s) that alter in impedance” (4) We request the SDT to clarify 4.2 by combining 4.2.1 into it, thus removing the separate 4.2.1. Please reword as follows: “These requirements contained herein are applicable to each 4.1 Functional Entity that owns Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements.”
Group
Bureau of Reclamation
Erika Doot
Yes
Reclamation appreciates and agrees with the drafting team’s clarification of the Purpose section. Reclamation agrees with the drafting team that it is more important for Protection System components to “operate in the desired sequence during Faults” than to have “the least number of power system Elements” isolated to clear Faults as previously stated in Draft 2 of the Purpose section.

No
Reclamation appreciates the drafting team's clarification of the definition of Interconnected Element to specify that Interconnected Elements must be "BES Elements." However, Reclamation believes that the addition of part b) of the definition is problematic. Reclamation believes that "Interconnected Elements" covered by the standard should only join facilities owned by separate Registered Entities as specified in part a) of the definition. Reclamation is not clear on how an entity would document internal coordination of Protection System Coordination Studies for the TO and GO arms of the same entity. Reclamation notes that the examples provided by the drafting team in the Application Guideline Diagrams appear to describe only Interconnected Elements at the point of demarcation between separate registered entities. At some Reclamation facilities, the same staff members coordinate TO and GO relay settings, so it is not clear how the studies and concurrence required under R1-R4 would be accomplished. Reclamation believes that PRC-023, PRC-025, and other standards will ensure that TO and GO relay settings are appropriate, and that PRC-027 should only address relay setting coordination where facilities join separate Registered Entities. In addition, the Background section of the standard explains that one purpose of the standard is to address the August 14, 2003 blackout report recommendation on the need to "address 'the appropriate use of time delays in relays,' by requiring that individual interconnected entities cooperate in designing and setting their Protection Systems to achieve coordination. Consistent with this rationale, Reclamation recommends that the drafting team modify the definition of Interconnected Element to read, "A BES Element that electrically joins facilities owned by separate Registered Entities." Finally, Reclamation notes that the definition of Elements in the NERC Glossary is, "Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components." By incorporating the term Element, PRC-027-1 perpetuates the ambiguous definition of Elements by including the term "such as," which creates an open-ended list of possible Elements. Reclamation believes it would be helpful for entities to have a better defined list of possible "Interconnected Elements" so that Entities can ensure compliance.
Yes
Yes
No
Reclamation agrees with this comment but suggests rephrasing R4 to encourage collaboration among registered entities. Reclamation suggests that R4.1 should read "Within 90 calendar days after receipt or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, R1.2) and respond to the other owner(s) by accepting the results or suggesting modifications to resolve any identified coordination." Reclamation does not believe that entities should submit formal rejections of PSCSs merely to satisfy the standard. Reclamation suggests that the phrasing above would better encourage collaborative relay setting coordination.

No
Reclamation requests that the drafting team clarify which Protection Systems “require coordination” for isolating faulted Elements, or remove the phrase “that require coordination” from the definition of Facilities.
Yes
Reclamation thanks the drafting team for assisting Registered Entities with the transition from PRC 001 to PRC-027 by incorporating the RSAW language to ensure continuity of compliance.
1. Reclamation requests that the drafting team clarify what "acceptable evidence" it envisions for PSCSs. For an example, is a PSCS acceptable if the document contains (a) Date of study, (b) Deviation of short-circuit currents, (c) System change, (d) all recipients, etc. We appreciate if you can include an example form/document as acceptable evidence. Reclamation would appreciate if the drafting team added a sample PSCS template that would be considered acceptable evidence. 2. In order to avoid similar vagueness of coordination issues that were problematic under PRC-001, Reclamation would appreciate if the drafting team clarifies what a PSCS should contain (e.g. which relay element(s) is required to coordinate with, how to show it as the evidence, etc.)The PRC-025 documents may provide helpful examples. 3. Regarding R1 & M1, if a PSCS shows no impact on the existing coordination (no setting changes are required), would an entity still have to send neighboring utility(s) the entire PSCS supporting study or would a brief statement of the study results suffice? Reclamation requests that the drafting team clarify the acceptable evidence. 4. Reclamation suggests that R2 should be revised to read, “For each interconnected element on its System, the TO shall, once every 60 calendar moths, technically justify if a fault current has changed more than 10% but does not affect to the Power System coordination, or …” rather than "techincally justify why Fault current does not affect the Protection System coordination." 5. Reclamation requests clarification of the items requiring coordination listed in R3.1. Reclamation believes that the current list implies that any changes in relay equipment or settings would require coordination.
Group
DTE Electric
Kathi Black
No
Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using the latest data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months.
Yes
None
Yes
None

No
Comments: Since the main purpose of this standard is to assure coordination of BES Interconnected Elements, there should be a provision included to require TOs to provide system fault data to DPs and GOs on a continuous basis so that coordination is performed on BES as well as non-BES elements using accurate data. If complete system fault study files are provided regularly (bi-annually?), projects can be completed using the latest data and not subject to re-evaluation when an update is provided by the TO every 60 months. It is critical that fault study data file compatibility exists between the short circuit programs of the different entities.
Yes
None
Yes
None
Yes
None
Comments: Different entities that are highly integrated electrically should be using the same short circuit data. If fault data files could be exchanged regularly (bi-annually?) using compatible file formats, short circuit databases wouldn't drift apart (as would occur after five years) and coordination studies could be performed with more confidence. Many settings could require re-visiting when the once every five year fault current update is received. It should be noted that while the emphasis is on BES Interconnected Elements, many other non-BES Interconnected Elements, such as radial distribution transformers, could be affected resulting in a negative impact on the BES.
Group
Southern Company
Pamela Hunter
No
Suggest that "the desired sequence" be replaced with "an acceptable sequence" to read: To coordinate Protection Systems for Interconnected Elements, such that Protection System components operate in an acceptable sequence during Faults. e.g. the GO and TO may not have the same desires.
Yes
Yes
Yes
Yes

Yes
No
While we agree with the changes made to the applicability section and the measurement section, we believe that it is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "…familiar with the purpose and limitations of …". Will compliance be evidenced by training records for individuals, the content of the training, or both? How might the "familiar with limitations" and "familiar with purpose" be separately evaluated in an audit?
(a) The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. (b) Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts. (c) There is no equation found in R2.2. (d) In R3.3, it is not clear when the 30 days starts - is it the 30 days following the change(s)? (e) R3.3 should be limited to Protection Systems associated with Interconnected Elements. (f) 4.2 can hold an entity hostage if the other Interconnected Element owner does not/will not accept/reject the changes.
Individual
RoLynda
Shumpert
Agree
SERC PCS
Group
North American Generator Forum Standards Review Team
Patrick Brown
No
The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
Yes
Yes
Yes
No
R4.2 can hold an entity hostage (and possibly non-compliant) if the other Interconnected Element owner does not/will not accept the proposed changes. This requirement is extremely objectionable for entities in deregulated markets, since the “firewall” separating the regulated

and deregulated sides of the business would ordinarily prevent the GO from seeing TO critical infrastructure information. R4.1 speaks of sharing only, “summary results,” but the Application Guidelines calls on p.24 for transmittal of, “power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings.” R4.2 also raises concerns for the situation in which a TO connects to GOs within the same corporate umbrella as well as to GOs that are part of completely separate corporate entities. The TO is legally required to treat all GOs equally, and we would certainly expect this to continue to be the case if PRC-027 is enacted, but suspicions could arise whenever expansion plans of a TO are impeded or overtly vetoed via PRC-027 “reject” decisions by an other-corporate-entity GO and vice-versa. Proposed changes to Interconnection Service Agreements are handled under market rules, and NERC standards should not contain features that might create opportunity for infringing-on or bypassing these rules.
Did you mean PRC-001-3? If so, the response is, “Yes.” We believe however that PRC-001 should be left as-is and PRC-027 should be made an exclusively TO-applicable standard, as explained elsewhere in these comments.
No
a. Did you mean PRC-001-3? b. It is not necessary to separate "limitations" from "purpose" in the VSL, and recommend that a single Severe VSL be used to cover all of R1 by using the requirement R1 verbiage "…familiar with the purpose and limitations of …" PRC-001 moreover should remain as is, with PRC-027 being applicable to GOs under only very limited circumstances, as stated above. c. The word “area” in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
a. R3.3 should be limited to Protection Systems associated with Interconnected Elements. b. There is no change needed to the present system: -The TOP is provided with detailed information of GO equipment via PRC-001 and MOD-010, and the TO (being informed of these inputs by the TOP) is then at liberty to modify their Protection Systems if needed. - We periodically request data for available fault current at the interconnect point from the TO, for use in our aux system short circuit studies Changes in the T&D system otherwise don’t matter to GOs. We do not modify our Protection Systems in response to changes to the Fault current at an interconnecting bus, we just trip the breaker if and when required to protect the generator and GSU (or if so commanded via a special protection system). Everything involving sequencing the tripping of multiple Elements is in the TO’s system. The most that could reasonably be asked of independent GOs is to have a valid Interconnection Service Agreement (ISA), since a coordination study is performed by the TOP prior to offering an ISA. Such studies remain in the possession of the TOP, not the GO, so detailed evidence could not be asked of the GO. The SDT states on p.21 of PRC-027 that “The drafting team has no evidence there is widespread mis-coordination between Owners of Facilities,” and, “records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” This appears to indicate that the present system is working and therefore there is no need to go back to existing unit’s coordination studies to make sure they crossed all of the T’s and dotted all of the I’s according to a standard that retroactively

applies requirements that were not in existence at the time of the original coordination studies. c. The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. Please retain one measure per requirement so that the Measurement numbers match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Individual
Brett Holland
Kansas City Power and Light
Yes
Yes
Yes, as long as the standard only requires documentation in cases where there are neighboring owners that need to agree on protection and control. As an owner of multiple functional entities, we believe that the BES would not benefit by an intra-utility documentation process, not when the required due diligence is already performed within our System Protection Engineering group. Our System Protection Engineering group is already responsible for the coordination of all protection, whether generation, transmission, or distribution.
Yes
The modification to a longer time frame is acceptable. However, we do not agree that there is adequate justification for requiring a fault current review every five years. Relay settings that are valid today will remain valid until changes are made at our end of an interconnected element or when another Registered Entity notifies us of change. A technical justification that is valid today will remain valid until changes are made to the BES within our system or a neighboring owner’s system.
Yes
Yes
Yes
1) The definition of Protection System Coordination Study should be changed to “A study that documents the intended sequence of operation for clearing faults of an existing or proposed Protection System.” The word “demonstrates” implies that live testing should be conducted to prove the sequence of operation. 2) In the Rationale for R1, Part 1.1.2, the following portion should be deleted, “e.g. when a line is protected by dual current differential systems with no backup elements set that are dependent upon fault current.” The deleted portion should be

replaced with “Refer to the Application Guidelines for Requirement R2 for examples of protection systems where technical justifications may be used.” 3) 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 required is if the fault current increases by more than 10%. Fault studies are typically conducted with all generation on, but we know that this is not the normal system configuration year round and the system could be operating below the 10% fault current threshold. Unit outages are anticipated and fault detecting elements are set to operate even during outage conditions. Elements that coordinate at higher fault current values will coordinate at reduced values. Our suggested change would not preclude a Registered Entity from initiating a Protection Coordination Study upon the reduction of fault current by 10%.
Group
Iberdrola USA
John Allen
Agree
NPCC
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
No
NSRF’s concern with the proposed definition is related to part B of the definition, on how to prove compliance in case of a vertically- integrated Registered Entity where one department is responsible for performing PSCS and the same Registered Entity is performing multiple functions. Recommend that the measures be updated for both part A and part B or clarity within the RSAW.
No
As currently written, each TO, GO and DP are required to perform a PSCS. This will lead to multiple efforts by each entity. Recommend that GO and DP be removed from this Requirement. Since the TO has access to the hierarchy of systems (Interconnected Elements) they are positioned to request current protection system settings from the GO and DP and then perform a PSCS. They can then request adjustments by the GO and DP in order to assure a more secure system.
Yes
Yes
Yes

Yes
PRC-027-1: The proposed standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Please consider revising the 30 calendar day's provision in requirements R2.2.1, R3.2 and R3.3 to 90 calendar days to avoid possible confusion between different timing requirements in the standard. We do not see a basis on why there needs to be different dates. If all dates were 90 days, it would provide consistancy for entities to follow. In consideration that the rationale for Requirement R1 Part 1.1.1 acknowledges that the drafting team has "no evidence there is widespread mis-coordination of Protection Systems associated with Interconnected Elements", LES recommends further development of the standard be halted until sufficient technical justification can be provided for the standard's development. As currently drafted, the drafting team would place excessive documentation requirements on registered entities for activities already being performed as industry best practices. In lieu of turning those best practices into compliance requirements, NSRF suggests the drafting team leverage existing Reliability Standard PRC-001 as a basis for system protection coordination. PRC-001-3: Please consider revising the Purpose of PRC-001-3 to reflect the one remaining requirement. With the updated measure there is an inconsistency between the Purpose, the Requirement, and the Measure. We suggest revising the Purpose to PRC-001, the following: To ensure familiarity with the purpose and limitations of protection systems operated by the entity. Suggest revising Requirement R1 to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection systems operated by the entity. The above rewrite now provides a clear and understandable (plus it adds to system reliability) Standard for the applicable entities to follow. The Standard sets a minimum level of training concerning protection systems that entities operate. An entity can always provide training on non-operated protection systems, whereby the entity has determined (based on risk to their system) the scope of training outside the proposed rewrite.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes
No
AECI remains unclear as to the intent and effect of PRC-027-1's definition for "Interconnected Element" with respect to clause-b, "the same Registered Entity…" clause. As written, this clause potentially captures all internal BES Elements that electrically joins any internal facilities owned within a Registered Entity that represents multiple functional entity responsibilities. Does clause-b intend to scope additional BES Elements: 1) that electrically join facilities between legally distinct entities within the same Registered Entity (including a JRO) that

represents multiple functional entity responsibilities (Distribution Provider, Generation Owner, or Transmission Owner), or 2) that (even within a JRO) electrically join only functionally distinct facilities within the same Registered Entity that represents different functional entity responsibilities such that internally included Elements join: DP-GO, DP-TO, GO-TO, while internally Excluded Elements join: DP-DP, GO-GO, TO-TO?
Yes
Yes
Yes
Yes
Yes
AECI seeks additional clarify of the SDT's intent as to how base PSCS requirements are to be applied within a JRO, and if R1-R2 serves legitimate reliability function, where R1.1.3, & R3-R4 do not apply to intra-JRO interconnected elements because JROs already internally do these; a JRO would still perform R1.1.3 & R3-R4 for interconnected elements with other registered entities; also clarify that R1 would only require one “master” PSCS for the JRO as opposed to multiple studies for each functional entity within the same JRO.
Group
SPP Standards REview Group
Robert Rhodes
Yes
No
Our concern with the way the definition is worded relates to how to prove compliance between separate entities as well as entities within a vertically integrated utility. How would a Registered Entity actually show that the proper coordination took place? In some instances it appears that evidence would have to be provided for coordination within the same department of an entity. On the other hand, if separate entities are involved, just what evidence would be required to show adequate coordination? Does this need to be formal documentation indicating all the owners of the interconnecting facility?
Yes
Yes

No
The way the requirement is currently worded, the sending entity could conceivably be found non-compliant if an entity receiving the results does not respond within 90 days. We would suggest incorporating language to clarify that the receiving entity has the obligation to respond within 90 days. This could be accomplished by inserting 'each recipient of the results shall' in the requirement. The requirement would then read "Within 90 calendar days after receipt, or according to an agreed upon schedule, each recipient of the results shall review the summary results of a PSCS…"
Yes
Yes
While we concur with the proposed measure, there does appear to be a mismatch between the requirement and the measure. See our comment in Question 8 below to address this issue.
PRC-027-1 As drafted the standard contains 30-day and 90-day timing requirements in addition to the 60-month requirement. Would the drafting team consider making the 30-day and 90-day requirements the same, for example 90 days? This would make staying abreast of timing issues much simpler. Figure 4, Application Guidelines The Note at the bottom of Figure 4 is misleading in that it states that no PSCS is required under this scenario. However, Transmission Owner R is required to have a PSCS for the Interconnected Element between Breakers A and B. The Distribution Provider S is not required to have a PSCS for Breaker C. PRC-001-3 Purpose The existing purpose does not fit the single requirement that is left in the standard. We would suggest changing the purpose to the following: To ensure familiarity with system protection schemes utilized within an operating entity's area. Requirement R1 Similarly, the requirement does not match the proposed measure. We suggest modifying the requirement to: R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall train its applicable personnel to be familiar with the purpose and limitations of protection system schemes applied in its area.
Group
ATCO Electric
Rowell Crisostomo
No
- R1 referring to other requirements with different timelines is very confusing to understand and execute. - R1 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timeframe", etc. - Requirement R1.1.2 – A 10% change in fault current isn't much in some areas of ATCO Electric's system, perhaps as little as a few hundred amps. This could lead to a burdensome requirement to frequently review the same areas of our system. Ten percent seems fairly restrictive when we typically use safety margins of 40% to 50% in selecting instantaneous overcurrent settings.

No
- R2 referring to other requirements with different timelines is very confusing to understand and execute. - R2 (and PRC-027-1 draft 3 in general) also has too many timelines: 90 calendar days, 60 calendar months, 12 calendar months, "agreed upon timeframe", etc.
Can the drafting team draw all timelines in 4 requirements together in a chart to see how these timelines fit together for an entity?
Individual
Jack Stamper
Clark Public Utilities
Yes
No
There still is some concern regarding coordination within a Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner). This type of Registered Entity is one organization and the standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one entity. The comments below provide specifics of these concerns. In order to address these concerns it is suggested that the words “separate” and “same” in this definition be capitalized for reference purposes. The definition should be modified as follows: Interconnected Element: A BES Element that electrically joins facilities owned by: a) Separate Registered Entities, or b) the Same Registered Entity that represents multiple functional entity responsibilities (Distribution Provider, Generator Owner, or Transmission Owner).
No
The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to “other owners”. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R1.2 Within 90 calendar days after the completion of each PSCS, provide to the other Separate Registered Entities that are owner(s) of the Protection System(s) associated with the

Interconnected Element(s), a summary of the results of each PSCS performed pursuant to Requirement R1, Part 1.1, (including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed).
No
The revised time frame of 60 months is agreeable, however, requirement 2.2.1 should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the updated Fault current study to provide the updated Fault current values (Iscs) to “each owner” of the Protection System associated with the Interconnected Element. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R2.2.1 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 Separate Registered Entity that is an owner of the Protection System associated with the Interconnected Element.
No
The response options are agreeable, however, requirement 4 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same organization that developed the Protection System Coordination Study to provide a document accepting it or rejecting it. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R4. Each Transmission Owner, Generator Owner, and Distribution Provider that is a Separate Registered Entity and each Same Registered Entity (on behalf of its multiple functional entity responsibilities) shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] 4.1. Within 90 calendar days after receipt, or according to an agreed upon schedule, review the summary results of a PSCS (per Requirement R1, Part 1.2) and respond to the Registered Entity providing the PSCS: • Accepting the results, or • Rejecting the results and suggesting modifications to resolve any identified coordination issues. 4.2. 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 Separate Registered Entities that are 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.
Yes
Yes
Requirement 3 (and any sub-requirements) should not be applicable to any Interconnection Element owners that are part of the “same Registered Entity that represents multiple functional entity responsibilities.” Often times there is only one person or department within a utility that is responsible for protection system coordination of all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the same functionally registered entity that developed the details for proposed changes to provide a documentation of those details to all other functionally registered entities. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner. Since the definition of Interconnection Elements incorporates the concept of “Separate Registered Entities and “Same Registered Entities” it is suggested that the wording be modified to incorporate theses terms as follows: R3. Each Separate Registered Entity and each Same Registered Entity shall provide to each other Separate Registered Entity connected to the same Interconnected Element: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning] 3.1. Details for any proposed change or addition listed below; either at an existing or new Facility associated with the Interconnected Element; or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s). • New installation, replacement with different types, or modification of protective relays or protective function settings, communication systems, current transformer ratios and voltage transformer ratios • Changes to a transmission system Element that alter any sequence or mutual coupling impedance • Changes to generator unit(s) that result in a change in impedance • Changes to the generator step-up transformer(s) that result in a change in impedance 3.2. Requested information related to the coordination of Protection Systems associated with an Interconnected Element, within 30 calendar days of receiving a request or according to an agreed-upon schedule. 3.3. Within 30 calendar days, details of changes made to Protection Systems during Misoperation investigations, commissioning, maintenance activities, or emergency replacements made due to failures of Protection System components.
Group
Cooper Compliance Corp
Mary Jo Cooper
Yes

We feel this is a good compromise to making the applicability the Transmission Planner. In our earlier comments we noted that we feel the drafting team should identify the Transmission Planner to be the entity who performs the studies as this is the function identified for the TP. The drafting team responded by stating they changed the Purpose.
Yes
We would like confirmation that this proposed Standard only requires a study for elements that have been determined to be BES elements. For example, a study would not be required on Elements that connect a radial line serving only load because by definition of BES, there are no BES elements to study.
Yes
Yes
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
Comments: The expression "the desired sequence" should be replaced with "an acceptable sequence," since the GO and TO may not have the same desires.
No
Section b) of the definition should be deleted. An “interconnected element” subject to these requirements should not include elements owned/operated by the same registered entity. To minimize the impact of equipment outages under fault conditions, coordination studies are routinely performed by vertically integrated utilities that own and operate facilities that extend from generation plants to distribution pole top transformers. The requirements appear to be intended to insure this same level of coordination is achieved between disparate owner/operators of upstream and downstream facilities. Moreover, as used throughout industry the term interconnected generally refers to electrically contiguous facilities belonging to different operators. After eliminating part b) of the definition, PRC-027 requirements would still apply to vertically integrated registered entities at each point of interconnection with facilities owned/operated by unaffiliated and separately registered entities performing as, e.g., DPs, GO/GOPs, neighboring TOs as appropriate.
No
There is no basis for performing studies every 60-months. Such studies should be performed when necessary based on predetermined criteria set forth in the standard. There is no

evidence of wide spread miscoordination of Protection Systems associated with Interconnected Elements. In fact, none of the recent blackouts resulted from miscoordination of protective settings.
No
See response to question 3 above.
No
90-days is not in all cases the appropriate time period to review such results. The terms and conditions for generator interconnections are regulated by FERC or state PUCs. The proposed reliability standard should clearly state that responsible entities are not obligated to take any actions that are inconsistent with the rights of the parties under any interconnection or similar agreements. Such agreements typically address the procedures for making modifications to a party's facilities that may affect the other party and the required notice and approval rights. The standard should not seek to impose any requirements that are inconsistent with these contractual rights. R4.1 speaks of sharing only, "summary results," but the Application Guidelines on p.24 lists as examples "power system configurations, protection schemes, schematics, instrument transformer ratios, type of relay(s), communication equipment applied for protection, and Protection System settings." We recommend that the above list be preceded with the words "summaries of."
No
Did you mean PRC-001-3? If so, the response is, "Yes."
No
a. Did you mean PRC-001-3? b. The word "area" in R1 of PRC-001-3 needs to be defined for compliance to be measured and enforced. The area for GOs should be restricted to the plants they own, if PRC-001 is modified (see other comments).
a. PRC-027-1, R3.3 should be limited to Protection Systems associated with Interconnected Elements b. There is no clear indication of need to change the present system. The SDT states on p.21 of PRC-027 that "[t]he drafting team has no evidence there is widespread miscoordination between Owners of Facilities," and "records collected for reliability standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations." The purpose statement for PRC-001-3 needs to be changed to match the content of the sole requirement. If this one requirement is to be absorbed by PER-005, consider keeping the purpose and moving the content of PRC-027 back into PRC-001. c. Please retain one measure per requirement so that the Measurement numbers in PRC-027-1 match the base requirement number. The evidence required for each sub part of each base requirement can be described in the same section as the other sub parts.
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC Protection & Control Subcommittee(PCS)
Individual

Joe Tarantino
SMUD
No
SMUD believes the purpose of this standard should state: “To coordinate Protection Systems for Interconnected Connection to help ensure Protection System components operate as expected for off-nominal conditions. We believe that the coordination is an effort to avoid misoperations a condition that may occur if the purpose statement is not met. We further believe that the coordination should not only cover a Fault condition but other intended operation that the protections scheme would cover, i.e. power swing, out of step tripping/blocking, etc.
No
SMUD believes the Interconnected Element should be defined as those BES elements that electrically join two or more facilities. SMUD disagrees with differentiating ownership as this delineates those requirements based upon ownership causing confusion and an administrative burden for those entities that solely own and coordinate protection components to demonstrate compliance for internal notifications.
No
The revised time frame of 60 months is agreeable, however, requirement 1.2 should not be applicable to any Interconnection Element owners that are one of the same Registered Entity that represents multiple functional entity responsibilities. There are several Registered Entities that have only one person or department within a utility that is responsible for protection system coordination for all protection systems (distribution facilities, generator facilities, and transmission facilities). The requirement as written would require the organization that developed the Protection System Coordination Study to provide a copy to “other owners”. The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
No
Please see our comments in Question #3; The standard should allow for the treatment of all of the registered functions within a Registered Entity that represents multiple functional entity responsibilities collectively as one owner.
Yes
Yes
The timing provided in R3.1 is contains no specification that correlate to the timing requirements of the other R3 subrequirements .
Group
SERC Protection and Controls Subcommittee

David Greene
Yes
Yes
As evident by a note in the rational box for R1 (pg. 6) the drafting team recognizes that vertically integrated entities that have the same personnel performing the review of protection systems for the function of the TO and GO could be unnecessarily burdened if the definition were misconstrued to the point of requiring these personnel to display evidence of comparing studies with themselves. To ensure that this intent is retained in the final version of the standard it is suggested that this note or some derivative be placed somewhere in body of the standard such as the definition of Interconnected Element or under the requirements.
Yes
Yes
Yes
Yes
Regarding the applicability to the Generator Operator, the registered function of the Generator Operator could exist as a centralized corporate function as well as a remote function at the generation station. The requirements are probably aimed at the remote function, but if the corporate function embodies an electrical design group that is “familiar” with the protection systems “in their area”, is that sufficient for compliance? The draft includes a description of applicable “Facilities”, but the question still applies.
Yes
The requirement still calls for “familiarity” with the protection systems “in their area”. The extent of “familiarity” comes into question as well as the question of what constitutes “their area”. The newly crafted Measurement attempts to give some detail as to what that means. But if training is the expected means of achieving compliance, why not just require the training? And if training is expected, then the scope of that training should be related to application of a systematic approach to training, not a scope identified by the SDT, or an area arbitrarily selected by the auditors.
Please change Figures 3 and 4 so that “Interconnected Element” is adjacent or points to the line between Breaker C and the point of connection (tap point) on the line between Breakers A and B. It clarifies these examples by having the Figures align with your wording. (The Figures presently imply that the line between Breakers A and B is the “Interconnected Element”.) The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual

Mike Hirst
Cogentrix Energy Power Management, LLC
Agree
North American Generator Forum (NAGF) Standard Review Team (SRT)
Individual
Jim Howard
Lakeland Electric
Agree
FMPA (agree with their comments)
Individual
Brian J Murphy
NextEra Energy
No
The end of the sentence should read: . . . . desired sequence and time during Faults.
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Larry Watt
Lakeland Electric
Agree
Lakeland Electric concurs with FMPA comments.
Individual
Anthony Jablonski
ReliabilityFirst

No
a. ReliabilityFirst requests clarification on the term “Interconnected Element.” First, is the term “facilities” referring to the NERC Glossary of Terms defined term “Facility”? If so, this term needs to be capitalized. Furthermore, if this is the intent, with a Facility being defined as “a set of electrical equipment that operates as a single Bulk Electric System Element”, there seems to be no need to add the term “BES” to the beginning of the definition. ReliabilityFirst recommends capitalizing the term “facility” and deleting the term “BES” from the definition.
No
a. ReliabilityFirst believes the shift from 48 calendar months to 60 calendar months is an excessive amount of time to allow an entity to perform a Protection System Coordination Study (PSCS). With the effective date of the standard being 12 months beyond the date that it is approved by applicable regulatory authorities, this is essentially giving entities over six years to perform their initial study, for equipment that previously had no study performed. Furthermore, from a reliability perspective, this coordination is most likely already occurring in some capacity, when the interconnection is made, and entities should not require this excessive timeframe to perform the study (i.e., as quoted from the SDT: “…there is no evidence of widespread miscoordination of Protection Systems associated with Interconnected Elements…”). ReliabilityFirst recommends a 24 calendar month implementation timeframe to limit any potential reliability issues as a result of shortcomings in the existing set of Standards.
ReliabilityFirst offers the following comments for consideration: 1) Requirement R1, Part 1.2 - ReliabilityFirst recommends converting the parenthetical last sentence “(including, at a minimum, the Protection Systems reviewed, the associated Fault currents used, any issues identified, and any revisions or actions proposed)” into four separate and distinct sub-parts. Separating these out will clearly spell out to the applicable entity and compliance auditors the specific items which are required to be provided. Listed below is an example for consideration: 1.2.1 Protection Systems Reviewed 1.2.2 Associated fault currents 1.2.3 Identified issues 1.2.4 Proposed revisions or actions 2) Requirement R2, Part 2.2 - Within both the clean and redline version of the posted draft standard, the equation referenced at the end of Requirement R2, Part 2.2 is inadvertently missing and therefore needs to be added back into the requirement.
Group
JEA
Tom McElhinney
Yes
No

Most of the standard (R1.2, R2.2.1, R3 & R4) should not be applicable to a Registered Entity that represents multiple functional entity where the same system protection group has responsibility for the protection of their entire control area.
Yes
Yes
Yes
Yes
Yes
Individual
John Allen
City Utilities of Springfield, Missouri
Agree
Southwest Power Pool Standards Review Group
Individual
Daniela Hammons
CenterPoint Energy
The draft for PRC-027-1 states: “records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” CenterPoint Energy considers the proposed requirements to be too prescriptive for Protection System coordination when it has not been identified as a reliability issue and expects such requirements would provide little, if any, reliability benefits. We believe the majority of existing Interconnected Facilities have time-proven and fault-proven Protection System set points and that newer facilities, including replacement relay panels, are commissioned utilizing appropriate coordination studies that include necessary interaction between interconnected entities. CenterPoint Energy recommends reevaluating the need for this standard with

consideration that this subject area could instead be addressed by continuing to focus on misoperation analysis and through best practices initiatives.
Group
Tacoma Power
Chang Choi
No
Suggest removing the word ‘components.’ A Protection System operates together. If the SDT elects to retain the word ‘components,’ clarification of the intent of this word in this context is requested.
No
There is some concern about the language in part b of the proposed definition of an Interconnected Element. In some cases, a Registered Entity may have one engineering group that is responsible for all Protection Systems, regardless of registered function. Part b of the proposed definition seems to suggest that documented PSCSs, including coordination activities, could be required by proposed PRC-027-1 even if the same engineering group is responsible for all Protection Systems associated with the Interconnected Element. A distinction should be drawn between a Registered Entity in which one engineering group is responsible for Protection Systems associated with its DP, GO, and TO functions, as applicable, and another Registered Entity in which a different engineering group is responsible for Protection Systems associated with its DP vs. GO vs. TO functions, as applicable.
Yes
Yes
Yes
Should the Flowchart be updated to reflect the course of action if an entity rejects the results and suggests modifications to resolve any identified coordination issues?
No
The level of detail in the Applicability section appears to be inconsistent with the language in M1 “…training in basic relaying…” For this reason, it is recommended not to include the ‘Facilities’ portion.
Yes
Tacoma Power appreciates the efforts of the SDT. This is a difficult process and topic on which to standardize. It would help, especially for the Flowchart, if R1.1.3 could be separated into a revised R1.1.3 “according to an agreed upon time frame to meet the schedule when proposing or being notified of a change, as described in Requirement R3, Part 3.1; or technically justify why such a study is not required” and a new R1.1.4 “within six calendar months of being notified of a change as described in Requirement R3, Part 3.3; or technically justify why such a

study is not required.” In R3.1, the language “or at other Facilities when the proposed change modifies the conditions used in the coordination of Protection Systems associated with the Interconnected Element(s)” appears to be very open-ended with respect to the second, third, and fourth bullets under R3.1. In theory, any impedance change within an entity’s system could qualify, which brings into question potential overlap between R2 to address incremental changes and R3.1. R3.1 should establish a brighter line for what triggers an entity to begin coordination activities for proposed impedance changes not at an existing or new Facility associated with the Interconnected Element. In other words, at what point is an impedance change considered an incremental change and, therefore, applicable to R2, as opposed to R3.1? In the Flowchart, the arrows are confusing above the decision diamond “(R1.1.3) Is a new PSCS required?” Referring to M2, M5, M7, and M8, is any confirmation of receipt required in order to demonstrate that a responsible entity ‘provided’ the information? It is recommended that evidence of receipt not be required to demonstrate that an entity ‘provided’ information applicable to these measurements. Referring to the Application Guidelines, Figure 5 and associated discussion, the introductory paragraph statement “in Figure 5 below, Transmission Owner S has no direct Protection Systems located at Station 1 that need to be check for coordination with Generator Owner T” appears to contradict the discussion on page 39 of 40 of the redlined copy of PRC-27-1.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
No
Since there are no guidelines on who “applicable personnel” are, and there are no guidelines on what type of training is required and how often, this measure serves little purpose should be removed. Measures and VSLs are overly complex and will be difficult to effectively track as written.
1) PRC-027-1 R3.2 has a deadline based on the date of receiving a request. There should more

details regarding what constitutes receiving a request. If informal channels are used, there may be disagreement about whether the 30 day deadline was met. The complexity of this standard becomes all the more evident when looking at ways to implement and track all the measures. For many of the measures, the only practical way to capture time frames is to tie communications with an interconnected entity to a task within an established schedule. Communications with interconnected entities will likely need to become more limited and formal to become more trackable. Bringing tractability to emails and other communications for evidence will be a significant issue, with the need to capture communications of out-side resources performing studies as well as the use of secure email requiring tedious offloading or screen captures of communications from secure servers. It would be recommended that acceptable evidence demonstrating the time frames should allow for documented processes along with activity schedules providing start and completion dates. More detailed evidence should be signed and verified studies, which indicate that validated models and remote settings have been utilized in the analysis. Here are our specific recommendations by requirement and measure: a) Requirement R1- R1.1.3- It would be recommended to be consistent with the time frame as specified in 1.1.2 and change the specified calendar months to read “or within 12 calendar months of being notified of a change as described in Requirement R3, Part 3.3.” M1, M2 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. b) Requirement R2 – R2.2- Allowance should be made to allow for tracking of fault level trends at the bus based on a 10% change in fault level for the year of the coordination study. M5 - Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. (VSL) Violation Security Levels- Each security level should provide consistent time frames to avoid confusion in tracking. c) Requirement R3 – M7 – A data request should indicate that it is being made per requirement R3 of PRC-027 to be measured under M7. M6, M7, M8- Acceptable evidence demonstrating time frames should allow for documented processes along with activity schedules providing start and completion dates. d) Requirement R4— R4- Study submittals should be required to stipulate that the study is being submitted per requirement R4 of PRC-027 to be measured under M9. M9, M10- Acceptable evidence demonstrating that the time frames have been met should allow for documented processes along with activity schedules providing start and completion dates. 2) 4.2.1 Applicability: For Generator Owners, many elements that are covered under the PRC-019, PRC-024 and PRC-025 (and future Phase 3 Loadability Standards) also fall under the Facilities Section of this draft of PRC-027-1, as the functions exist for the sole purpose of allowing coordination for faults to clear external to the generator. The elements covered by other standards should be excluded from applicability, in order to avoid a double jeopardy situation. Instead, we recommend that a list of applicable elements be identified. Typical functions are identified below. We believe these to be the only functions applicable to the standard as far as a GO is concerned. - Ground Time Overcurrent Relay – (Directional Towards the System) (51G) - Neutral Time Overcurrent Relay – (Directional Towards the System) (51N) - Ground Directional Time Overcurrent Relay – Directional Toward Transmission System (67G) - Negative Phase Sequence Overcurrent (46) In addition, please

consider adding a list of excluded elements, such as these: - Phase Distance (21) (Covered under PRC-025) - Volts/Hz (24) (Covered under PRC-024) - Undervoltage (27) (Covered under PRC-024) - Reverse Power (32) (Not applicable to standards as it is protection for the generator) - Loss of Field (40) (Covered under PRC-019) - Inadvertent Energization (50/27) (Not applicable to standards as it is protection for the generator) - Breaker Failure (50BF) (Not applicable to standards as it is protection for the generator) - Phase Time Overcurrent Relay (51) (Covered under PRC-025) - Phase Time Overcurrent Relay – Voltage-Restrained (51V-R) (Covered under PRC-025) - Phase Time Overcurrent Relay – Voltage Controlled (51V-C) (Covered under PRC-025) - Overvoltage (59) (Covered under PRC-024) - Field Overvoltage (59E) (Covered under PRC-019) - Stator Ground (59GN/27TH/64S) (Not applicable to standards as it is protection for the generator) - Field Ground (64F) (Not applicable to standards as it is protection for the generator) - Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Covered under PRC-025) - Field Overcurrent (76E) (Covered under PRC-019) - Out of Step (78) (Covered under Future Phase 3 Loadability Standards) - Frequency (81) (Covered under PRC-024) - Differential (87) (Not applicable to standards as it is protection for the unit) Alternatively, perhaps a table listing excluded elements could be added to the back of the standard, and referenced in the 4.2.1 Applicability section. Here is an example of what 4.2.1 might look like: “4.2.1 Protection Systems installed for the purpose of detecting Faults on Interconnected Elements of the BES and that require coordination for isolating those faulted Elements with the exclusion of the elements listed in table XXX. “ 3) Regarding R2 M3 - Our technical justification to exempt the above excluded elements is: a) duplication in applicability to other standards, and b) the type of fault. Mandating technical justification beyond these two points puts an unnecessary burden on industry resources.
Individual
Mary Downey
City of Redding
Agree
SMUD
Individual
Tony Kroskey
Brazos Electric Power Cooperative
Agree
ACES Power Marketing
Individual
Bob Thomas and Kevin Wagner
Illinois Municipal Electric Agency
Yes
No

Illinois Municipal Electric Agency suppports comments submitted by Florida Municipal Power Agency.
No
Illinois Municipal Electric Agency suppports comments submitted by Florida Municipal Power Agency.
Yes
Yes
Illinois Municipal Electric Agency (IMEA)supports comments under Question 8 submitted by the SERC EC Protection and Control Subcommittee. Also,IMEA requests that Figure 3 be modified or a separate figure be included to clarify guidelines for DP systems that include only non-BES generation. IMEA also requests that Applicability Section 4.2.1 be revised to prevent inconsistency with the FERC-approved interpretation of transmission Protection System as specified in PRC-005-1b. Very specific attention/consideration needs to be given to avoiding unnecessary expansion of applicability to facilities owned by small Distribution Providers; i.e., unnecesarry expansion of scope to protective devices owned by a DP that have no potential adverse impact on the BES. Both FERC and NERC have stated the need to minimize impacts on small entity resources.
Individual
Bret Galbraith
Seminole Electric Cooperative Inc.
(1) In proposed PRC-027-1 R2, Seminole believes that the Reliability Coordinator (RC) should have the responsibility of performing any studies or analyses and the distribution of those studies/analyses required under R2 instead of the Transmission Owner (TO). In peninsular Florida, the RC has access to the data needed for the analyses and having a single entity perform the analyses and distribution will assure uniformity across the region. (2) In proposed PRC-027-1 R2-2.2.1., Seminole believes the 10% threshold for fault current is too low, as this percent change occurs daily. Seminole recommends the 10% threshold value be increased to 20% for fault current. (3) In proposed PRC-027-1 R2, is the 10% change in fault current study

based on the individual TO's system contribution as an island at the interconnection bus, or does it include all other interconnection that border the TO's system that could provide fault current, i.e., how many buses out from the TO's other interconnections does the study require for determining available fault current? (4) In proposed PRC-027-1 R2, Seminole believes that the requirements and guidelines for the Protection System Coordination Study (PSCS) need to be more specific and give additional detailed methodology. (5) In proposed PRC-027-1 R3-3.1, it should be noted that current and voltage ratio changes do not necessarily indicate a change in the protection system if the protective relay set points are adjusted accordingly. Therefore, R3-3.1 should be revised to reflect that certain ratio changes do not require notification.