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Question 5 Comments (33 Responses)
Question 6 Comments (33 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
What is meant by "condition based"? Condition-based (referred to in Part 1.3) should be clarified in the Rationale Box for Requirement R1. It is implicit in requirement R1 that setting development is implicit in the process. The Drafting Team should consider deleting Part 1.5. It is addressed in Part 1.2. A Part should be added to address the implementation of the coordinated settings to Protection System equipment. There is no need for a quality or review process in this standard. As per Paragraph 81, the "how" is not necessary. It is the responsibility of the engineering or technical staff to implement their in-house process.
Yes
A Protection System misoperation should be a trigger. Our comment response to Question 2 suggested that possibly a Part be added. An addition or change to the interconnecting Elements can be used as a minimum trigger.
No
Parts 2.1 through 2.3 address interconnections. FERC was concerned with the standard not addressing the coordination of Protection Systems within a Transmission Owner's footprint, referred to as "internal" or "intra-entity" Protection Systems. A Part (or Parts) must be added to specifically address that concern. Wording still needs to be added to capture FERC staff's intent. The technical justification for selecting the 200kV threshold in Part 2.1 needs to be provided.
Yes
A definition for "coordination" should be developed to eliminate some of the variations in Protection System design philosophies. The language in Introduction Section 4. Applicability sub-Part 4.2.1 creates a potential hole in Protection System coordination. In some applications, Protection Systems are installed for the purpose of detecting Faults on non-BES Elements but may impact the BES if they are incorrectly set. For example, a radial delivery point tapped off a BES transmission line may have a blocking relay installed that does not appropriately detect faults in its designated zone of protection, causing the transmission line terminals to trip impacting the BES. Suggest that the wording of 4.2.1 be revised to read: 4.2.1 Protection Systems installed for the purpose of detecting Faults on BES Elements, and isolating those faulted Elements, and including those Protection Systems that if improperly coordinated could result in BES Element tripping. The Purpose of PRC-001-1.1 is "To ensure system protection is coordinated among operating entities." The Purpose of PRC-027-1 is "To maintain the coordination of Protection Systems installed for the purpose of

detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults." The industry definition of coordination is "Coordination of protective devices is the determination of graded settings to achieve selectivity." "Selectivity in a protective system refers to the overall design of protective strategy wherein only those protective devices closest to a fault will operate to remove the faulted component…". Protection System coordination achieves selectivity, not only with interconnections, but within a Transmission Owner's footprint. PRC-001-1.1 already addresses what PRC-027-1 is addressing. Efforts should be directed at improving PRC-001-1.1 rather than producing a new standard.
Individual
Barbara Kedrowski
Wisconsin Electric Power Co
No
While a process is needed to do this work, I don't think requiring a process should be part of the standard. At the end of the process there needs to be documented evidence that the Protection Systems are coordinated (as stated in R2). I think that the standard should focus on the final product, not require a process to get there.
No
: I don't see "develop Protection System settings" between 1.1 and 1.2, but perhaps it is implied. Part 1.5 should be done while developing the settings rather than at the end so if they don't coordinate you have to start all over again. However, this would require getting the neighboring entities related settings (part of 1.4) prior to developing your own settings. We would have a different sequence for coordination, so as stated in question 1, this shouldn't be part of the standard. Part 1.3 seems misplaced as it is when a review is required; this would be needed as part of the standard.
Replacement of protection elements other than like in kind replacements for failures.
No
Along with the definition for Interconnected Element, the Elements listed in parts 2.1 through 2.3 seem unclear. The way I read it if a line connects two Registered Entities, then only the Protection Systems for that line need to be coordinated. I don't think that is what the drafting team intends.
No
As stated in question 1, I don't think developing a process should be part of a standard.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
No
- For 1.2, rather than a review process of the protection system settings, is it the intent to have a process to review the protection system coordination, or a process to review the development of the protection settings? - Similar for 1.3, the trigger should be for a protection system coordination review? - For 1.4, should it include a procedure to communicate any identified coordination issues on the interconnecting elements with other entities?
It may need very careful considerations to define this trigger; otherwise entities may end up wasting lots of precious resources on doing this review.
No
It is not clear exactly what coordination documentation is required. It is inherent that protection systems at both ends of the interconnecting elements would need to work together properly, but there is no "coordination" required between the protection systems at both ends of the interconnecting elements. Is the intent to require the protection systems on the BES elements adjacent to the interconnecting elements coordinate with that of the interconnecting elements themselves?

Yes
- This version of the standard applies to all BES elements; which is a big shift of direction from previous versions where it applies to the interconnecting elements only. The SDT should take careful pre-cautions that this new standard will not create unnecessary burden for protection system owners. - The title of the standard is confusing. Consider changing to: “Protection System Coordination During Faults”?
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
No
Ingleside Cogeneration LP (“ICLP”) does not see the overriding need to completely overhaul PRC-027-1 just to account for transmission links internal to the TO’s network. In general, the process – which was nearing industry’s approval – will suffice provided those links are limited to a reasonable subset of substation-to-substation connections. In our view, this may require further vetting to properly identify the affected components, but the general concept should not change. It does not make sense to throw away several years of work without taking this step first.
Yes
ICLP does not disagree with the elements of coordination captured in R1.1 through R1.5, but is concerned that the lack of specificity in the criteria could become a major issue. It has been our experience that determinations seemingly left completely to Registered Entities, in this case the TO, GO, and DP; will be overridden by CEAs wherever binding language is not used in the standard (e.g.; in the requirement). This inevitably leads to an uneven assessment of compliance by audit teams – which is in conflict with the fundamental concept of continent-wide standards.
In Draft 4 of PRC-027-1, the industry reached near-consensus that a 10% change in Fault current across an interconnecting bus was the proper trigger. Consistent with our response to Question 1, if the scope of the standard is expanded to only include a subset of substation-to-substation located within the TO’s footprint, that triggering criteria does not need to change. It seems to us that it only becomes an issue if other parameters other than Fault current are considered – which extends beyond the concern expressed by FERC staff.
No
On the whole, ICLP agrees that the 60 month baseline should apply to a limited subset of Interconnecting Elements. However, we do not understand why generator interconnections to the transmission system are not limited to those operating at 200 kV and above – just like the corresponding connections between adjacent TOs are. This would be consistent with other standards – FAC-003-3 comes immediately to mind – who also have focused their efforts on the most critical transmission systems.
No
ICLP believes the Measures are directionally correct, but cannot provide our viewpoint one way or another when the requirements are so undefined.
ICLP was comfortable that the previous drafts of PRC-027-1 clearly identified those relay systems that react to a Fault. However, this latest draft is written at a much higher level – which makes no distinction between relay schemes which may appear to react to a Fault, but are actually triggered by secondary conditions resulting from one. For example, a Generator Owner has many relays that monitor voltage, frequency, and ground current which may damage equipment if action is not taken to isolate it. Based on our reading of PRC-027-1, it may require us to take steps to limit Fault-related transients or adjust relay ride-through thresholds wherever dynamic studies show a risk – even though accurate simulations of such phenomena are difficult to achieve. If this is not the intent, the drafting team may have to provide a list of applicable relays and a list of exclusions. This is the same issue that the development team for the Definition of RAS is addressing – and is not an easy determination. A better solution would be to re-use some of the language deleted from PRC-027-1 Draft 4, which is accurately focused on Fault coordination.
Individual
Jonathan Meyer

Idaho Power
Yes
Yes
Yes
A time based interval should be the default, perhaps every five years. Additionally, system topology changes in the vicinity of existing schemes, e.g. two buses, would trigger a recheck of a protection systems.
Yes
Yes
Individual
David Jendras
Ameren
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Yes
Triggers should include additions or removals of system elements electrically adjacent to existing elements, system misoperations and increases in short circuit levels similar to those proposed in the earlier version of this standard. Decreases in short circuit current are problematic because a system coordination must include maximum short circuit levels but must also allow for generators and other sources to be off line which means the minimum fault currents under normal conditions can be substantially less on an operational basis.
R2.3 applies to "any monitored Facility of an [IROL] while R2.1 and R2.2 apply to Elements. If there is a distinction between monitored Facility and Element it should be specifically clarified. If not, then R2.1, R2.2 and R2.3 should all use the glossary term to either Elements or Facilities consistently.
Yes
Coordination of protection of a single element such as prescribed in section R2 will involve the protections of other electrically adjacent and possibly non-adjacent elements. This cascading effect will be difficult to define may extend far beyond the prescribed Elements and could ultimately involve most of the BES. How will the limits of compliance with this standard be defined. This could also result in a burdensome amount of effort and documentation.
Individual
Gul Khan
Oncor Electric Delivery LLC
Yes
No
This question is really two questions that Oncor answers No (Do you agree that Parts 1.1 through 1.5 of Requirement R1 are essential) and No ("Are there others that should be included") Oncor believes that Part 1.5 should be modified to read; "A procedure to verify any identified coordination issue(s) for all Interconnecting Elements associated with proposed Protection System settings are addressed prior to implementation." Part 1.5 should not be applicable for an "internal" or "Intra –

entity” processes. Part 1.2 in its “quality assurance or review process” should take care of the requirement for resolving coordination issues prior to implementation of Protection System settings for all “internal” or “intra-entity” Protection System settings.
Yes
Oncor believes that the present Requirement R1 part 1.3 is sufficient (“A set of minimum triggers to prompt a review of existing Protection System settings. Specified triggers may be time-based, condition-based, or a combination of the two”). Adding a list of minimum trigger(s) to Requirement R1 Part 1.3 would imply that an entity does not have the freedom to choose triggers that are not found in the set of minimum triggers of Part 1.3. Therefore Oncor proposes to add these triggers within a “Rational” box.
Yes
Yes
Individual
Andrew Pusztai
American Transmission Company LLC
Yes
ATC has no comments.
No
While Parts 1.1 through 1.5 contain elements of what is needed for a successful protective relay setting practice, as proposed, Parts 1.1 through 1.5 appear to pose a heavy administrative burden on the company required to implement its processes. In particular, R1.5 appears particularly impractical. ATC sees very little benefit in a separate process, given that a fundamentally sound setting process should prevent implementation of improper settings. Adding a separate administrative regulatory burden to meet this requirement misdirects resources from higher value tasks. Furthermore, the term “identified coordination issues” is subject to interpretation and needs to be better defined in the standard (R1.4 and 1.5). Finally, ATC suggests clarifying what is expected of the “quality assurance or review process,” which would currently be performed in R1.2.
ATC suggests the following triggers: 1) a risk-based trigger based on the company’s own installed equipment whereby the company knows which relays are more likely to misoperate; 2) a trigger that evaluates misoperations of similar technologies. If the criteria is too prescriptive, opportunities may be lost to address the most impactful to reliability.
Yes
ATC has no comments.
No
Measure 1 states that, “acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has implemented its process to coordinate its Protection Systems…” As written, the measure is very broad and has the potential to generate a large volume of evidence open to various interpretations of regulators.
The process outlined in Requirement 1, Parts 1.1 through 1.5, exhibits characteristics of industry best practices, such as those developed by industry forums and trade groups. ATC recommends that industry best practices continue to be handled outside the NERC Reliability Standards as they have been previously. Placing them in a regulatory framework will lead to inefficiencies due to administrative burden and lead to slower improvement in reliability.
Individual
Thomas Foltz
American Electric Power
No
AEP believes that R1 should be limited to the establishment of a process to coordinate BES Protection Systems, rather than the implementation of a process. M1 indicates that registered entities will be required to provide records to demonstrate the application of the developed process

for all BES Elements. A robust coordination process should be focused on ensuring that Protection Systems are set to operate in the intended sequence, rather than on producing documentation that adheres to a reportable format that can be easily understood by all. Registered Entities should be required to establish a coordination process and be trusted to follow the process. This would allow relay engineers to focus their time on ensuring proper coordination rather than preparing documentation. We believe the evidence described in M1 would be acceptable if it was to apply only to Interconnecting Elements. Additionally, AEP has concerns regarding how R1 will be audited and believes that as currently written, that it may be too subjective and open to auditor interpretation. For example, how does one determine what constitutes a quality assurance process? How much latitude would an auditor have to deem the entity's process inadequate and subsequently issue a potential violation of R1 based on Parts 1.1 through 1.5? NERC Standard PRC-005-1 uses a similar approach, requiring entities to "have a Protection System maintenance and testing program" and to implement it. AEP urges the drafting team to consider the difficulties industry has had with PRC-005-1 R1 when drafting PRC-027.
No
While we agree what that these may be essential elements of a successful coordination process, we don't agree that such elements should be within the scope of an audit as their application can be subjective and open to auditor interpretation.
Yes
AEP does not believe that the standard should prescribe a specific set of minimum triggers for all Registered Entities to follow. Entities should be provided the flexibility to define within their process what should prompt a new coordination study. Rather than using the phrase "minimum trigger", AEP believes it would be more appropriate for R1.3 to refer to a defined methodology that includes conditions for performing coordination studies. For example, "A defined methodology to identify what system conditions should prompt a new coordination study". A potential condition described within this methodology could include when settings are reviewed due to a system change (line, transformer, generator). In these cases, coordination in a given area would be reviewed outwardly from the system change until it is determined that no additional settings changes are needed to achieve coordination. AEP believes that this proposed methodology would be adequate to identify changes to system conditions and perform coordination as needed.
No
As stated in our response to Question #1, AEP believes that R1 should be limited to the establishment of a process to coordinate BES Protection Systems, rather than the implementation of a process. M1 indicates that registered entities will be required to provide records to demonstrate the application of the developed process for all BES Elements. A robust coordination process should be focused on ensuring that Protection Systems are set to operate in the intended sequence, rather than on producing documentation that adheres to a reportable format that can be easily understood by all. Registered Entities should be required to establish a coordination process and be trusted to follow the process. This would allow relay engineers to focus their time on ensuring proper coordination rather than preparing documentation. We believe the evidence described in M1 would be acceptable if it was to apply only to Interconnecting Elements.
There are some situations where performing a coordination study does not need to be performed because it does not provide any technical value. The draft should be revised to allow Registered Entities to technically justify why a coordination study does not need to be performed. The previous draft allowed for this, but has been removed. There will be times when a relay setting is found to be incorrect for various reasons. The discovery of such a condition might be due to a Protection System Misoperation. PRC-004-2 allows entities to identify such conditions and take corrective actions as necessary to resolve the relay setting issue. Since in these cases the relay did not operate in the intended sequence, would this become a reportable violation of PRC-027? AEP believes that to best promote reliability of the BES, entities should retain the ability to identify and correct settings issues as they are found without the need to report a violation of a Reliability Standard.
Group
Puget Sound Energy
Dianne Gordon
Yes

Yes
Yes
Yes
Yes
Individual
Chris Scanlon
Exelon Companies
No
We believe that R1 is overly burdensome from a compliance perspective and is not necessary to reach an adequate level of reliability for the BES. Creating a new process and procedure does not add much value and further evaluating compliance with this requirement will be very subjective. Instead SDT could identify the requirements and ask compliance with the same. Changing R1 as below would provide for an adequate level of reliability without creating a lot of unnecessary compliance work. In current draft, propose that the word “implement” in R1 be changed to “have”. M1 would accordingly be changed so that the entity could produce the appropriate process documents as evidence for R1. No other evidence would be required.
No
The word “essential” in this statement conveys a weight that is not justified and may lead to complex and unwieldy processes where simple ones will suffice. This is a standard that addresses a problem that has not, in practice, been a problem. I agree these are elements of a successful coordination process, but they create an extreme burden of documentation when simple communications between peers is all that is really needed. We do not believe that triggers are needed to assure protection system coordination. We do not use triggers in any procedures or processes we currently have that prompt a coordination review. Misoperations on our system are essentially non-existent and have been for decades. Thus we propose that the drafting team remove R1.3 as it is not necessary to provide an adequate level of reliability for the BES. The SDT should rather simply require of the Generation owner that any time protection system settings are changed, that needs to be coordinated with TO. This process and procedure requirement with triggers is burdensome and complicated for GOs.
No
The bulk of coordination changes are condition based; they will be required by the addition or reconfiguration of BES facilities or changes to protection systems. Coordination changes required by an increase in fault current levels will almost always be identified in the process of reviewing coordination for the change to BES facilities. Requiring a burdensome process to periodically review and document fault current based triggers adds very little value and adds a layer of unneeded complexity, which can ultimately detract from the goal of creating a more secure protection system. Based on our experience operating a large power system, we do not believe that triggers are necessary to assure coordination and an adequate level of reliability for the BES. We encourage the drafting team to re-think the need for codified triggers to prompt coordination reviews. We believe that selection of triggers should be by the registered entities, based on their own experience and engineering practices, and not designated by the compliance authority. Appropriate triggers might include the addition of a new transmission line (200kV or higher), a new generator (1000 MVA or higher), or a new autotransformer (1000 MVA or higher), change of XFMRS (MPT, UAT and SAT) or Generator or change in any of their parameters.
Yes
We have no suggestions for adding additional circuits. It is our understanding that these R2.1, R2.2, and R2.3 circuits are the only circuits required to be reviewed to meet this standard and we agree with the drafting teams decision. Review of other circuits is necessary to provide an adequate level of reliability. Thus, we suggest that the drafting team clearly reflect this in the Facilities section of

the standard. Specifically 4.2.1 could be changed to read “Protection Systems installed for the purpose of detecting and isolating Faults on the following BES elements; list those specified in R2.1, R2.2, and R2.3. Exelon GO’s question does this include protection for Generator, MPT or SAT in addition to the connecting leads between switchyards and GO owned transformers or just the connecting leads?
No
See Q 1. M1 would accordingly be changed so that the entity could produce the appropriate process documents as evidence for R1. No other evidence would be required.
This is an example of an extremely burdensome standard when there are really very few misoperations that are caused by miscoordination of protection on interconnecting facilities. To make the standard and implementation easier for the GO, SDT needs to identify the specific GO owned relays which should be coordinated with TO. For example distance relays, overcurrent relays; negative sequence relays etc. do require coordination while differential, reverse power, Generator ground etc. do not require any coordination. Same should be done for the TOs relays which require review by the GO.
Group
ACES Standards Collaborators
Jason Marshall
Yes
We are intrigued by this new approach and cautiously optimistic that this approach is an improvement over previous drafts that contained very detailed performance requirements and numerous administrative requirements. While this new approach does appear, in essence, to expand the reach of the standard to all BES Protection Systems from just those Protection Systems for Interconnecting Elements, we believe requiring a process document is a better approach. This is especially true since the performance aspects will be limited to Interconnecting Elements that are 200 kV and above or that are connected to generator(s) with 75 MVA capability and Facilities that are part of an IROL per R2.
No
(1) Overall, we agree with these Elements, but believe that the SDT should provide additional clarifications for small entities. For example, since R1 applies to TOs, GOs, and DPs, can a small entity, such as a small G&T cooperative, have a single process document? If so, the SDT needs to modify Part 1.4 to be clear that it would only apply to communication and coordination with other Registered Entities and not other functional entities assigned to the same Registered Entity. In essence, Part 1.1 would cover “Interconnecting Elements” between the small G&T’s different functional entities , which would make more sense, particularly in cases where there is a single protection engineer. In this situation, how would the protection engineer document their self-communication per Part 1.4? (2) Implementation of Part 1.2 could be a challenge for small entities, especially small distribution cooperatives that own transmission Protection Systems and likely have a single protection engineer. Some guidance on expectations in the quality assurance or review process for these entities would be helpful since they likely cannot implement a peer or supervisory review.
One obvious trigger would be a Misoperation; however, this trigger would need to be coordinated with PRC-004 to avoid overlaps in the standards. Other triggers would include: system topology changes impacting the impedance (a threshold could be set) seen by the Protection System, generation additions, expansions, or retirements.
No
While we do not have an issue with focusing compliance monitoring on the specified Elements identified in R2, we do believe the requirement in its current form meets Paragraph 81 criteria. A Paragraph 81 criterion states that a requirement should be retired if it only compels production of documentation. Since R1 already compels coordination, R2 is would appear to be a documentation requirement that should be struck. The reason documentation became a Paragraph 81 criterion is because documentation is required to demonstrate compliance with other requirements. Furthermore, NERC can compel the production of the documentation via other processes such as compliance monitoring (e.g. audits, spot checks), section 1600 data requests, or possibly even include these specified Elements in the RSAW as part of the data sampling process. Since FERC

ultimately approved these Paragraph 81 criteria when they approved the retirement of the requirements meeting the criteria, we cannot see how R2 should remain in its current form as it is not consistent with a prior Commission order.
No
(1) We are concerned that M1 could cause an auditor to believe that they need to review evidence for every single Protection System setting since it states that the responsible entity must have evidence of implementation. We need to avoid this burdensome compliance approach to be consistent with the RAI. We suggest that the drafting team should work with NERC compliance staff during the development of the RSAW to be clear that a sampling approach will be used. (2) We believe that the M2 is too vague. What kind of records is being asked for? For example, would output from a software package such as Aspen be the desired evidence?
(1) We believe that the main requirement for R1 should ask for a plan rather than a process and that Parts 1.4 and 1.5 should ask for processes. Since setting relays occurs in the operations planning horizon, use of plan and procedure may not technically fit the category of an Operating Plan and Operating Process, as defined in the NERC glossary; however, use of plan and process, as described above, would be consistent with the definitions and may avoid some confusion. It may even make sense to use the defined terms. (2) Since R2 is intended to be an “one-time performance requirement necessary to establish a baseline of coordination”, will this requirement be retired after the baseline is established? We believe it should be. (3) Will a Protection System Misoperation indicate that a violation of R1 has occurred? We would suggest that should not be the case, but an auditor could interpret such a Misoperation as an indication that the Protection Systems did not operate in the “intended sequence during” a Fault. The drafting team should be careful to avoid a Misoperation automatically indicating a violation because it will discourage reporting of Misoperations and the lessons learned entities share with the rest of industry.
Individual
Michael Moltane
ITC
Yes
No
1.5 is not essential because it is part of 1.4 process of seeking concurrence from the other entity. Calling this one aspect out specifically provides no reliability benefit and only increases administrative compliance burden to track dates, etc.
No
We agree the chosen Elements are more critical than others. However we suggest removing this requirement as there is no evidence of widespread miscoordination, per SDT in previous drafts of this standard.
No
M2 needs to include evidence of coordination from prior to effective date of the standard.
Group
Dominion
Connie Lowe
Yes
Yes
Yes
The SDT needs to explain the basis for selecting the 200kV threshold in Part 2.1.
Yes

Dominion is concerned about a potential hole in Protection Coordination created by the language in section 4.2.1. In some circumstances, Protection Systems are installed for the purpose of detecting Faults on non-BES Elements but may impact the BES if they are incorrectly set. For example, a radial delivery point tapped on a transmission line may have a carrier blocking relay installed that does not appropriately detect faults in its designated zone of protection, causing the transmission line terminals to trip, impacting the BES. Dominion believes the language should be modified to include Protection Systems that, if improperly coordinated, could result in a BES Element tripping.
Individual
John Merrell
Tacoma Power
Yes
Tacoma Power agrees with the concept of requiring a process to address the coordination of Protection Systems. However, great caution must be exercised that entities and their ratepayers are not overly burdened for marginal reliability gains. While having such a mandatory and enforceable standard may create additional incentive for entities to periodically review Protection System coordination, mandatory and enforceable standards risk significant administrative cost if not carefully crafted.
No
It is not completely clear what Part 1.1 is trying to achieve. Is this part intended primarily to refer to short circuit models? If so, this should be more clearly stated.
Because this will be a mandatory and enforceable standard, the triggers should be clear and pose minimal burden to entities to monitor even if the triggers do not comprise an all inclusive set. The following four triggers are suggested: -The 3LG or 1LG fault current at the bus to which the protected equipment connects has changed by some percentage (e.g., 10%) relative to a baseline. This approach was proposed in previous drafts of PRC-027-1. This trigger is intended primarily to maintain coordination over time as the power system evolves, resulting in incremental changes that can have a potentially significant cumulative effect. (One possible issue with this trigger is that Generator Owners may not have immediate access to this information and would therefore be dependent on their Transmission Owner to trigger the review.) -An alternative to this trigger could be a time-based trigger. The interval should be no shorter than once every five calendar years, and a ten calendar year interval may be more reasonable. Tacoma Power maintains that an entity should be permitted to choose between a time-based trigger and a trigger based upon changes in Fault current (or a comparable trigger) and that en entity should be able to make this choice either globally or per Protection System (or protected Element). -There is a change in the impedance or topology of a protected element. For example, a line is segmented, a transformer is replaced, or a new power system Element is installed. In general, assessing coordination would go one zone back to include remote backup protection. -There is a material change to a Protection System. This trigger would include cases in which (1) the power system is not changing but a Protection System is or (2) the power system is changing elsewhere and cascading Protection System changes are required. Example of (1): An entity is modifying their protection philosophy. Example of (2): A segmented line resulted in changes one zone back, which resulted in a review of the backup protection one zone further back; if changes are needed, a review may be needed even one zone further back.
No
It seems that Requirement R2 may raise some of the same concerns that FERC staff expressed previously. That is, FERC may expect that baseline documentation of coordination of all Protection Systems applicable to PRC-027-1 be established. This may be true particularly if a trigger will be established based upon a change in bus Fault current. Requiring initial documentation of coordination would have a comparable burden as a time-based trigger. If Requirement R2 is expanded, and if a condition-based trigger is selected that looks at some parameter like bus Fault current, then an entity should only have to monitor for that condition after Requirement R2 has been satisfied in whole. It should also be noted that, if Requirement R2 is expanded, implementation of Requirement R2 could result in some miscoordination during a transition period because it will not be practical to review and change all Protection Systems at once; therefore, there could be a period of elevated risk to the BES. If the drafting team elects to limit Requirement R2 to Interconnecting

Elements, then Part 2.2 seems out of place when one entity may be both the Transmission Owner and Generator Owner and one group is responsible for all of the Protection Systems involved.
Yes
As the drafting team is aware, Protection System coordination will not be maintained under all contingencies (of power system Elements or Protection Systems components). Sensitivity to contingencies will depend upon multiple factors including Protection System philosophy and vintage of Protection System components. This issue should be acknowledged in some form, either within this standard or within application guidelines. Tacoma Power suggests that “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements” be changed to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements from the BES.” In other words, add “from the BES” at the end. Some Protection Systems installed for the purpose of detecting Faults on the BES may trip non-BES elements as well (e.g., non-BES generation connected to a tap on a transmission line). These portions of the Protection System should be excluded. The drafting team has taken great care to acknowledge that different entities have different philosophies. Tacoma Power does not proposed that Protection System coordination philosophies be included in PRC-027-1, but the lack of standardization of Protection System philosophies may make coordination more difficult to achieve in some cases. Standards like PRC-023 and PRC-025 have taken bold steps to settle philosophical differences among some protection and operations personnel. Might this level of standardization ultimately be needed to help entities coordinate Protection Systems associated with Interconnecting Elements? The NERC definition of Fault is “an event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.” It is Tacoma Power’s understanding that the purpose of PRC-027-1 is primarily, if not exclusively, to maintain coordination during short circuits. Broken wires (when there is no accompanying short circuit) and intermittent connections are generally not the subject of coordination studies. Furthermore, coordination during high-impedance Faults, especially during contingency conditions, may not always be possible/practical. Tacoma Power requests that the purpose of the standard be restricted to short circuits, even if this is acknowledged in application guidelines. Alternatively, the definition of Fault could be revised as part of this project. Regarding Requirement R1, some allowance should be acknowledged, perhaps in application guidelines, that an entity may include in its process a mechanism to identify de minimus impacts, which could result in a variance to, or waiver of, the process. The goal is reliability. The drafting team should be applauded for its patience through all of these drafts. It is unfortunate that FERC’s concern was identified after four drafts were balloted, even though none of the earlier drafts addressed “internal” or “intra-entity” coordination.
Group
Tennessee Valley Authority
Brandy Spraker
Group
SERC PCS
David Greene
Yes
Yes
Requirement 1.5 seems unnecessary because the process of coordinating settings is not complete until all issues are resolved.
The list of triggers needs to be concise and it needs to be communicated that an entity’s process will not need to include all triggers. Reasonable triggers are: change in fault current, removal or addition of elements to a station/bus, line reconductoring, or time based per the entity’s specification.
Yes
R2 and its subparts 2.1, 2.2, 2.3 provide a clear and acceptable scope of facilities covered by this standard. Requirement R1 aligns with how industry typically performs Protection System coordination. The statement made in the Background section above: “The primary concern was that the proposed standard did not address the coordination of Protection Systems within a Transmission Owner’s footprint, referred to as “internal” or “intra-entity” Protection Systems” appears to propose

greatly increasing scope of facilities to possibly be covered by this standard. We support the scope of facilities as currently stated in R2, but would not agree with increasing the scope of facilities within R2 as we believe them to be adequately addressed within the process for R1.
Yes
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
Amy Casuscelli
Xcel Energy
Yes
R1.1 is very ambiguous and appears to say that a method to updata "data" is needed for compliance. This is a very ineffective stipulation as it is on the surface very menial (i.e. data collection?). A more useful stipulation might be to have a methodology concerning how the settings should be developed, and what guidelines are used during the coordination analysis. We agree that is it an improvement from the prior version in that the entity can design their coordination process to meet the requirements.
Yes
R1.5 is vague with the use of the phrase "any identified coordination issues." This could be interpreted many different ways depending on the different relay philosophies and methods between TO's, GO's and DP's. What is an "identified coordination issue" to one TO, may not be a "coordination issue" for another TO. See suggested language in our response to question 6.
Yes
It is not clear. Will the requirement change to include the soon to be identified triggers? or is the generic criteria (time, condition) going to remain?
No
The 60 months portion of the requirement seems to be something that should be addressed in the Implementation Plan of the standard, and not stated (repeated) in the requirements section. The requirement should be modified to just state that the registered entities "...shall have documentation that..." Also see response to Question 6
Yes
We read M1 to mean that entities can determine what eveidence is required for coordination based on the self created processes created pursuant to R1 and R1.1-R1.3.
We believe that R1.4 & 1.5 don't belong within R1 since they relate specifically to Interconnecting Elements. We recommend a structuring similar to: R1, R1.1 -1.3 as currently proposed. R2 Each Transmission Owner, Generator Owner, and Distribution Provider with Interconnecting Elements: - associated with Transmision operated = > 200KV - associated with BES Generating resource(s) - Any monitored Facility of an Interconnection Reliability Operating Limit (IROL). shall develop and implement a process to coordinate Protection Systems of the Interconnecting Elements, to include, in addition to requirements stated in R1.1 through R1.3: R2.1 A procedure to communicate the Protection System settings with Transmission Owners, Generator Owners, and Distribution Providers associated with Interconnecting Elements and seek concurrence that there are no concerns with the proposed Protection System settings. R2.2 A procedure to resolve, prior to implmementation, with other entities of Interconnecting Elements any concerns associated proposed Protection System settings.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes

No
1. 1.3 Does one trigger such as ‘every x years’ meet the intent of a ‘set of minimum triggers’. 2. 1.4 ‘ ... there are no identified coordination issues...’ should read ‘ any identified coordination issues have been addressed (or resolved?)’. Since a needed change in settings may require other changes that will be accomplished after the fact. 3. However, some of the details appear to be duplicative. These include the following two items: 1) R1.1 vs R1.3 where 'method to review' of R1.1 and 'triggers to review' of R3.1 are the same detail; 2) R1.2 vs R1.4 vs R1.5 where 'QA or review process' of R1.2, 'communicate settings and seek concurrence' of R1.4, and 'procedure to verify any identified coordination issues are addressed' of R1.5 all are essentially the same notion.
Yes
See response #1 to Q2. X years, y% change in fault current, change in system within z busses away, addition or retirement of generation within z busses away, etc
Yes
1. We agree with the element identified and believe it is appropriate for our system in that it will cover the intent of the Reliability of the BES. 2. With the scope of Transmission Owner Protection Systems specified by R2.1 being at and above 200kV, does it not follow that the GO Generating resources in the scope of R2.2 should also be limited to those connected at and above 200kV to align the Protection Systems to be compared in R1.4? 3. However, should there be a provision to capture more of the interconnections it the case that the system is comprised of all or a significanbt amount of <200-kV?
Yes
We agree with the present scope related to Interconnecting Elements and believe that there is a reliability benefit to this approach as has been reflected in our past affirmative votes on this Standard. We would not support the expansion of the applicability of R2 to include all elements of the BES nor the inclusion of lines internal to the entity other than those noted in R 2.3.
Group
Duke Energy
Colby Bellville
Yes
No
1.1.: No comment 1.2: Duke Energy suggests removing the phrase “quality assurance” from part 1.2 of Requirement 1. We feel that the idea of “quality assurance” is already inherent in the coordination of Protection Systems in or between entities. Also, “quality assurance” may be viewed as being too subjective to demonstrate compliance during an audit. 1.3: No comment (See question 3.) 1.4: We seek further clarification from the drafting team on part 1.4. Is this requirement already covered in PRC-001, and if so, will it be removed from PRC-001? It appears that if kept, there is potential for non-compliance of two requirements in two different standards. Also, we suggest replacing “procedure” with the term “method” to maintain consistency with part 1.1. 1.5: Duke Energy requests further explanation as to the intent of the drafting team for part 1.5. As currently written, it would be difficult to write a single procedure for numerous coordination issues that could arise. We suggest replacing “procedure” with the term “method”, for the reason mentioned above, as well as to maintain consistency with part 1.1.
Duke Energy prefers that the minimum triggers be Condition-based. We do not prefer Time-based triggers based on the possibility that no fault duties have changed since the last study. We feel that the triggers should be Condition-based, based on a certain percentage of change, if any changes have occurred.
No
Duke Energy asks for clarification from the drafting team on the selection of 75 MVA for subpart 2.2. A concern is that some individual dispersed generating resources operate above 75MVA, and are connected to 115kV. This would require the testing of those 115kV elements. We submit for the drafting team’s consideration, an increase of the 75 MVA level, or the insertion of a caveat to eliminate unnecessary testing. See the suggested language revision for 2.2 below. “Interconnecting

Elements associated with BES Generating resource(s) with gross plant/facility aggregate nameplate rating greater than 75 MVA if operated at 200kV or above. We feel this language revision reduces the likelihood of bringing in those individual dispersed generating resources that operate below the 200kV level.
Yes
Individual
Muhammed Ali
Hydro One
No
This concept is very confusing. The current wording in R1 requires the entity to carry out or implement a process then R 1.4 and R1.5 require procedures – so procedures within a process. Suggest wording change to “…. shall have a program in place to coordinate…” – that program could include procedures. Of course this has been happening in most places but this will create a huge documentation burden for entities
Yes
Notwithstanding our comments in Q1, these more or less would be necessary steps to ensure coordination. However we offer some comments: R1.1 This requirement is too generic. What does this requirement really mean? Needs more specificity – what kind of data? R1.2 We generally agree with the concept but for this standard should be limited to coordination only R1.3 Do these triggers prompt a review of the coordination across the entire entity’s system? Of course keeping track of all system changes that necessitate a coordination review will be a documentation nightmare for condition based triggers. R1.4 This sub-requirement has 2 actions – communicate the settings, then seek concurrence. Likely needs to be broken up into 2 sub-requirements. We assume this needs to take place initially then subsequently when a review is triggered?
We believe the triggers identified in earlier versions of this standard are adequate. However in line with comments in Q2, how wide of an area needs to be studied?
Yes
Yes
1. The purpose statement is confusing. Is the intention of the standard to assume protection systems are coordinated already and the standard is to “maintain” that co-ordination? 2. Also the wording in the purpose statement “such that the Protection System components operate in the intended sequence during Faults” is misleading. This implies some sort of coordination of the components of the individual protection system, implying the need for SOE etc. Suggest “…such that Composite Protection Systems between Elements operate in the intended sequence during Faults”. 3. Similar to PRC-023 and PRC-026 it will be helpful to have an appendix with the list of elements that will require coordination in this standard (based on the SPCS whitepaper). Previous versions of the standard referenced coordination of other non-fault protections would occur in other standards. Yet for instance there is no requirement in PRC-026 to coordinate out of step protections on adjacent Protection Systems. Otherwise too much latitude will be provided to an auditor.
Group
Pacific Gas & Electric Company
Aaron Feathers
Yes
No
We do not believe that Requirement 1.5 is essential since it is part of the process in Requirement 1.4. Requirement 1.4 could be modified to add "verify" to combine these two requirements. "1.4 A procedure to communicate the Protection System settings with Transmission Owners, Generator

Owners, and Distribution Providers associated with Interconnecting Elements and [verify] that there are no identified coordination issues."
A 10% or greater change in Fault current is an appropriate trigger. For a time based trigger, not less than 5 calendar years.
Yes
We agree with the chosen elements.
Yes
In general, we agree with the measures. A 5 calendar year interval is preferred over a 60 calendar month interval due to utility budgetary cycles for the funding to perform the routine coordination studies.
Group
PPL NERC Registered Affiliates
Stephen J. Berger
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. There is no apparent need for PRC-027-1. Its purpose, “To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements, such that the Protection System components operate in the intended sequence during Faults,” appears to be just a subset of the PRC-001-2 purpose, which is, “To ensure system protection is coordinated among operating entities.” Some explicit duplications are also apparent - R1.1-1.3 of PRC-027-1 are already covered by PRC-019-1 regarding voltage regulating functions, the procedure called-for in R1.5 seems to be nothing more than R2 of PRC-001-2, and the settings of loadability relays are covered by PRC-023 and PRC-025. R1.4 appears to mandate that every Protection System setting implemented by a DP, GO or TO be communicated to all other DPs, GOs and TOs that the entity connects-to, which would create a burdensome flood potentially unnecessary information. Even if R1.4 communications were pared-back to information that the receiving party wants to know, the, “seek concurrence,” portion of R1.4 is too weak. Would sending an email that may never get answered be sufficient? R2 is even more unworkable, requiring coordination among entities without any direction on how this is to be accomplished. Such lack of clarity might not be a problem for vertically-integrated utilities, but in competitive markets there must be a lead entity. An uncooperative entity could otherwise cause all parties that it connects-to to incur a PRC-027 R2 violation. Project 2007-06 should be terminated and, if any gaps in coordination can be found, they should be addressed via updates to PRC-001, PRC-019, PRC-023 and/or PRC-025. In the event that NERC still wishes PRC-027 to proceed it should at least be made inapplicable to GOs, because the only sequence-of-tripping issue for such entities is that they ride-our disturbances until load-shedding schemes have been implemented, and this achievement is ensured by PRC-024.
No
See the response above to question #1.
No
See the response above to question #1.
No
See the response above to question #1.
Group
FirstENergy Corp
Richard Hoag
No

FirstEnergy agrees with the need for a reliability standard to ensure relay coordination on ties between different Transmission Owners, but does not agree that a reliability standard is needed for internal Transmission Owner coordination. Experience has shown that relay mis-coordination (i.e. relays tripping in the wrong sequence due to timing or pickup setting errors) has been the root cause of a misoperation far fewer times than other setting issues, such as directional element settings. However, FE believes that for the special case of relays that are owned by two different companies does warrant a reliability standard to ensure that the information necessary to perform relay settings coordination flows freely between the Transmission Owners involved.
No
FirstEnergy agrees that, in general, the items listed in Parts 1.1, 1.2 are elements of a successful coordination process. For Part 1.3 FirstEnergy supports the triggers developed previously for draft 4 of this standard. For Part 1.4 and Part 1.5, coordination may not be possible for extreme system conditions. Perhaps incorporating a statement such as “under reasonable contingency conditions” or pointing to contingencies studied as part of PRC-023 attachment B or that are part of TPL standards may be appropriate. Also, Part 1.5 includes the phrase “settings are addressed prior to implementation”. Clarification is requested on this statement. There can be cases where a large system upgrade (such as building a new substation) will require settings changes at many remote substations – most likely ground overcurrent backup settings. What most often happens is that some of these settings can be changed before the new substation goes into service, but in some cases applying settings intended to be used after the new substation is built would negatively affect the reliability of the BES during the time period prior to energization of the new substation. Is Part 1.5 referring to the calculation of settings? Or actual field implementation?
No
Since these triggers will have a large impact on the efforts required to comply with this standard, FirstEnergy supports using the triggers already vetted through the Standards process in draft 4 of this standard.
Yes
FirstEnergy agrees with the spirit of the requirement but believes the initial implementation is better described in an Implementation Plan rather than a one and done requirement. The standard should be clear on any initial requirements in an implementation plan and the requirements should clearly describe any ongoing expectation whether event driven or periodic update driven.
Yes
An implementation plan was not included with this draft. However, FirstEnergy believes that a period of time for entities to create, review and/or update the documents required in 1.1 and 1.2 should be established prior to enforcement action being taken for the other requirements of this standard. Suggest 12 to 18 months.
Individual
Glenn Hargrave
CPS Energy
No
Please keep this from going down the PRC-005-1 road, where many companies received fines because of poorly written procedures and inconsistent auditing methods and interpretations across regions as opposed to inadequate maintenance. We would be more supportive if the process were created as part of a regional process that was put upon the Planning Coordinators or Regional Entities to create/approve instead of each end user.
No
First, not sure what a quality assurance or review process is. Secondly, Part 1.4 will be problematic if different entities have specific communication procedures for seeking concurrence. Finally, Part 1.5 addresses proposed settings, but what about existing settings.
A trigger should be a change in the impedance or ratings of elements connected to interconnecting busses. However, this change should be set to a percent change not just any minor change (e.g. re-route of a couple of towers). Also, if relevant elements of protection systems located at the interconnected busses are modified, then this could trigger a review as well.

Yes
No
M1 is too open for interpretation.
Individual
Manon Paquet
Hydro-Quebec Production
Yes
Coordination of all Protection Systems (not just BES Protection Systems) is fundamental for the design and operation of power systems. It's also a good practice to have a process to describe the coordination methodology. Do we really need a standard to obligate the industry to implement a process?
Yes
There could be different un-formal ways to communicate coordination issues with other entity associated with Interconnected Elements
Protection misoperations, modification of the protected Elements, modification of the short-circuit level
Yes
Documentation, database or acceptable evidence demonstrating that the Protection Systems for the specified Elements in Parts 2.1 through 2.3 are coordinated.
Yes
We agree with the principle of "Acceptable evidence"
Individual
Patricia Robertson
BC Hydro
Yes
Yes
BES configuration change, Mis-operation
Yes
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Some trigger points to consider: - Significant (~10%) change short-circuit fault currents (this is what the previous draft version included). - Addition of new generation. - Increase of transmission capacity (new lines and/or transformers). - Introduction new zero-sequence sources (certain types of transformer connections). - Change in the protection scheme.
Yes

Yes
Group
Bonneville Power Administration
Andrea Jessup
No
The stated purpose for earlier drafts of this standard was as follows: “To coordinate Protection Systems for Interconnecting Elements, such that Protection System components operate in the intended sequence during Faults.” In this latest draft, the scope and purpose of the standard have been greatly increased to include “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted Elements.” This change from Interconnected Elements to all BES Elements represents a broad increase in regulatory scrutiny to an area where BPA feels it provides little to no increase in system reliability. BPA is aware of no evidence to indicating that widespread mis-coordination of BES Protection Systems is a problem which is in need of a regulatory attention. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard.
No
BPA notes that numerous industry guides, white papers, text books and professional development courses have been devoted to the subject of successful relay coordination. BPA believes it is beyond the scope of this standard to delineate the essential elements of a successful coordination process. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard.
BPA believes Functional Entities must be left to apply their own engineering judgment and resources when developing reasonable triggers for the review of relay settings. BPA does not support a NERC standard to define time, system event, or conditional triggers which all of the industry must follow. To do so will certainly increase the number of unnecessary violation most of which will be of an administrative nature. Take for example the installation of a large transformer at a single substation. Without a doubt settings in the area will require review but how many busses or lines should be involved in this review, to what extent should a wide area coordination study be conducted, can this review wait until the next periodic settings review? Many of these questions are based on engineering judgment and knowledge of the local system which may differ from what is prescribed by the drafting team. BPA would prefer that the intent of this standard remain the regulation of information exchange between Functional Entities. BPA proposes R1 be removed from the standard. If R1 is not removed, BPA suggests at least the development of triggers for settings review must be left to the Functional Entities.
No
The delineation of the 60 calendar months time frame presumes that all Functional Entities will have adopted at a minimum a 5 year time-based review trigger for Protection System settings. As stated earlier, BPA is opposed to the drafting team’s development of a set of minimum triggers. Therefore, BPA proposes that the wording be changed as follows: Each Functional Entity shall document the exchange of information sufficient to coordinate Protection Systems on Interconnecting Elements which meet the BES definition whenever the following conditions are met: 2.1 New Protection System installation. 2.2 Significant change to an existing Protection Systems or its settings. 2.3 Information is requested by a Functional Entity for the purpose of Protection System Coordination.
No
BPA proposes Measure M1 should be removed with all of Requirement 1. BPA suggests Measure M2 should be altered to reflect the recommended changes to R2: Acceptable Evidence includes but is not limited to, electronic or physical dated records demonstrating the exchange of information for changes or additions made to Protection Systems on Interconnecting Elements which meet the BES definition.
Individual
John Brockhan

CenterPoint Energy
Yes
CenterPoint Energy appreciates FERC’s concerns on coordination of Protection Systems within a Transmission Owner’s footprint, even though it appears protection coordination issues have not been a major factor in events reported through NERC’s Event Analysis program, nor a predominate root cause of reported Misoperations collected for Reliability Standard PRC-004. The preliminary draft of Requirement R1 for Draft 5 of PRC-027-1 appears to be a reasonable and logical approach to establishing a mandatory requirement to address coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements. CenterPoint Energy believes such an approach recognizes several things: the majority of existing Protection Systems have time-proven and fault-proven Protection System set points; entities do have existing processes for protection coordination and have been performing protection coordination studies; and, this will bring in a very large number of Protection Systems into the mandatory scope for coordination, especially on 100 – 200 kV systems. Furthermore, the approach utilizing “triggers” allows coordination of these Protection Systems to be phased-in more gradually and as needed.
No
(1) CenterPoint Energy recommends deleting Requirement R1.2 from the standard as we do not agree that a quality assurance or review process is an essential element for a successful protection coordination process. We expect that there are numerous, existing coordination set points that were successfully established without such a process. CenterPoint Energy is also concerned that the use of “Protection System settings” in Requirement R1.2 is overly broad and could be interpreted to include protection settings not associated with a protection coordination study. (2) If Requirement R1.2 is not deleted, CenterPoint Energy recommends clarifying “Protection System settings” as used in Requirement R1.2. The proposed wording for Requirement R1.2 states: “A quality assurance or review process of the Protection System settings.” CenterPoint Energy recommends rewording Requirement R1.2 as the following: “A quality assurance or review process of the Protection System [coordination study].” (3) In addition, CenterPoint Energy recommends clarifying Requirement R1.5 which currently states: “A procedure to verify any identified coordination issue(s) associated with proposed Protection System settings are addressed prior to implementation.” Requirement R1.5 appears to be related to Requirement R1.4 that provides for communication between entities on Interconnecting Elements. CenterPoint Energy suggests the following wording for Requirement R1.5: “A procedure to verify any identified coordination issue(s) associated with proposed Protection System [set points] [for Interconnected Elements] are addressed prior to implementation.”
Yes
CenterPoint Energy agrees with the chosen Elements in Parts 2.1 through 2.3 and does not have any suggestions for additional Elements to include in Requirement R2.
No
Measure M2 uses the term “Responsible Entity” which is not defined in the proposed standard or in the NERC Glossary of Terms Used in NERC Reliability Standards. As this standard uses Functional Entities in the Applicability section, CenterPoint Energy expects that “Responsible Entity” should be changed to lower case. In addition, Measure M2 appears to indicate that the documentation must be from protection coordination studies performed within the 60 months after the effective date of the standard. This does not allow for the use of documentation of protection coordination studies performed prior to the effective date. CenterPoint Energy recommends clarifying Measure M2 to allow previous protection coordination documentation, especially considering that there are presently many growth and reliability projects in progress. One way to provide clarity is to delete the wording at the end of the sentence after Requirement R2 concerning 60 months after the effective date of the standard. Including modifying the term “Responsible Entity”, Measure M2 would be as follows: “Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the [responsible entity] coordinated the Protection Systems for the Elements identified in Requirement R2[].”
Group
SPP Standards Review Group

Shannon V. Mickens
No
We ask the drafting team to conduct an analysis between FAC-001-1 and PRC-027-1 to ensure that there are no redundancy issues between the documentation. However, we still have concerns about the time commitment for documentation in reference to the internal coordination process and that it will not help improve reliability for the BES Elements. We agree with the concept contained in Requirement R1; however, we don't agree with scope of the internal coordination process for PRC-027-1.
We generally agree that Parts 1.1 through 1.5 of Requirement R1 includes the essential elements for the coordination process. However, we would ask the drafting team to provide more detailed information in the rationale box especially concerning the intent of Requirement R1.4 and R1.5. Some of our confusion was based around why was there a need for two procedures… along with proving compliance on the retrieval and coordination of the required data before implementation.
We would ask the drafting team to re-evaluate Measure M2 for we feel that the language should include coordination information prior to the 60 calendar month period as acceptable evidence.
Group
DTE Electric
Kathleen Black
No
If Documentation of Protection System Coordination is to be required, the specifics of the study should not be prescribed. Previous drafts did not dictate the specifics of a PSCS. However, Part 1.4 of R1 should remain to insure communication with other entities.
No
Each entity should be responsible for determining what makes up their coordination study/process.
This statement seems to already assume that a coordination process will be specified in the standard while Question 1 asks if one should be required.
No
If the intent of draft 5 was to change applicability from interconnecting elements to BES elements, shouldn't R2 be revised accordingly?
No Comments
None
Individual
Joe Tarantino
Sacramento Municipal Utility District
Yes
SMUD much prefers this process option to the previous options balloted. However, we continue to struggle with the idea that a standard is required to address intra-utility coordination. The greatest risk for a mis-coordination is at the seams between entities, not inside an entity.
Yes
SMUD agrees these steps form a coordination process. However, in smaller utilities, a rigid, formalized process is not required to ensure coordination and instead unnecessarily burdens the process with excessive compliance documentation. In contrast, large utilities require formalized processes and often have very specialized skill sets among their protection engineers and special facilities that require extra care. The SDT will need to develop a flexible process that applies to both.
We urge the SDT to develop flexibility into the process. SMUD currently uses the relay maintenance cycle to review settings. This makes our process time-based and in synch with the times found in PRC-005. We do this so that the relay tech makes only one trip to the relay. We are strongly opposed to any process that requires us to[[arbitrarily]] look for fault current changes and take actions out of cycle.

Yes
SMUD agrees with the three items listed, with the caveat that we feel coordination should be done only at the seams between entities and not internal to the entity.
No
The term “to demonstrate” in M2 leaves it too open at this point to know what depth of detail is needed. We are afraid we would need to show lots of coordination plots for every line, including the elements looking into the line and the elements the line looks out on. It seems to us this could balloon into a lot of paperwork. Perhaps an attestation by the engineer that the coordination was done per the process document would be sufficient?
We encourage the SDT to address functional obligations that would be managed by an internal group who would perform the actions in the requirement(s). This effectively eliminates the need for internal coordination and associate processes. As we have indicated in the previous responses we urge the SDT to allow an entity to coordinate relay settings, data and other associated equipment protection through an internal group.
Individual
Phil Hart
AECI
Yes
No
1. AECI believes the intended structure of this proposed standard is to require a process for all BES elements in a less burdensome R1, and require actual physical documentation in a more expanded, detailed R2. AECI agrees with this approach, however M1 currently does not reflect this approach. If the SDT intent of this standard is aligned with our interpretation, then the measure should not require actual documentation for the elements in R1, rather require only the procedure or process that is stated. Recommended language , [M1. Acceptable evidence includes, but is not limited to, electronic or physical dated records of the Responsible Entity’s process(es) to coordinate its Protection Systems, in accordance with Requirement R1 and its Parts.] 2. If the intent of R2 is to require documentation of coordination for a fewer, but more critical list of elements, then the cutoff levels for generation should reflect this. AECI would suggest the SDT move the 75 MVA cut-off to 1500 MVA to align with industry accepted definition of a generation level that is deemed critical to BES reliability. At the least, the 75 MVA cutoff should be increased to some point, if not 1500 MVA. 75 MVA units have very little to no impact on the BES, and including them in this documentation requirement would only reduce entity focus on those elements that are critical, such as IROL related elements, and 200 kV plus interconnections (which AECI agrees should be documented). 3. AECI believes that requirement 1.2 is too constrictive, and should allow entities other methods to ensure that protection system settings are accurate. One method of this (which AECI is in the process of developing) is using a standardized, reviewed, template for settings construction. Settings that fall out of this template would then be reviewed through some quality assurance program. The current 1.2 is very close to allowing this type of quality review, however please keep in mind this template approach when revising the standard as to not eliminate this option for quality assurance.
No
1. AECI would strongly suggest that for whatever triggers are developed, they be condition based and not time based. Developing time based triggers would lead to monotonous paperwork that would otherwise be unnecessary.
Yes
AECI believes 60 calendar months is a reasonable time for documentation of coordination. To clarify, would the SDT be able to state if there will be any cutoff for the age of documentation that will be acceptable (would coordination documentation from 10 or 20 years ago still be good?).
Individual
Nick Braden
Modesto Irrigation District