Individual or group. (47 Responses)
Organization (29 Responses)
Group Name (18 Responses)
Lead Contact (18 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (10 Responses)
Comments (47 Responses)
Question 1 (29 Responses)
Question 1 Comments (37 Responses)
Question 2 (29 Responses)
Question 2 Comments (37 Responses)
Question 3 (0 Responses)
Question 3 Comments (37 Responses)

Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
Yes
R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1 (i.e. there is not a relay that stands behind every limiter). Section 1.1.2 should be struck – as this is covered under the direction of other standards such as EOP-003. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. This is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. The term "blackstart unit material" in applicability para. 4.2.4 (p.2) is not understood. We suggest that the SDT remove the term "blackstart unit material" or clarify when a blackstart unit designated as part of the Transmission Operator's restoration plan would be immaterial. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in a Generator's possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability.
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Group
Northeast Power Coordinating Council
Guy Zito
Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.

Group
Pepco Holdings Inc and Affiliates
David Thorne
Yes
Yes
Attachment 1 and Attachment 2 have been revised since the last draft. In these latest set of attachments, although the Zone 2 loss of field characteristic has been set to operate prior to the Steady State Stability Limit (SSSL) is reached, it is also set so that it would operate prior to the generator capability curve being exceeded. This appears to be in conflict with the intent of the standard to ensure that protection should not operate before the equipment capability is exceeded. The Zone 2 characteristic should properly be set between the Generator Capability Curve and the Steady State Stability Limit. As such, Figures A.6 and A.7 in IEEE C37.102-2006 might be better coordination examples to use for these attachments.
Individual
Delmarva Power & Light Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Atlantic City Electric Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
Potomac Electric Power Company
Agree
Potomac Electric Power Company, Transmission Owner (Segment 1)
Individual
TransAlta Centralia Generation LLC
Yes
Yes
N/A
Individual
Manitoba Hydro
Yes
None.
Yes
None.
R1 - Manitoba Hydro finds the wording ‘At a maximum of every five calendar years’ awkward. We suggest changing the wording to read ‘at least once every five calendar years’. R1.1.2 - Manitoba Hydro suggests deleting R1.1.2 which reads, “The applicable in-service Protection System devices are set to operate, isolate or de-energize equipment, in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits”. Since these are fundamental functions of any protection system device, there is no need to include this in the NERC standard. R1.1.1 - Is AVR defined somewhere? We could not find its definition in the Glossary. General Comments - 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?. 2. The concept of equivalent unit testing should be applied to both synchronous condensers and generators. Equivalent units are addressed in Row 5 of MOD-027-1 Attachment 1, but it is not clear if this attachment applies to PRC-019. We would suggest that “Attachment 1” from MOD-027-1 be added to all of the standards included in this project. 3. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled “Consideration for early Compliance” with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar

language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1).
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
Regarding the "Functional Entities" listed in the Applicability Section, it is not clear how PRC-019 can only apply to TOs that own synchronous condensers because R1 & R2 require GOs to communicate with TOs regarding the generation equipment subject to the standard (units over 20 MVA, units connected at a common bus with total generation over 75 MVA, and blackstart units in the TOPs restoration plan). Regarding the "Facilities" listed in the Applicability section, BPA believes that Section 4.2.4 should apply to blackstart units designated as part of a TOP's restoration plan. The phrase "material to and designated as part of" the restoration plan creates ambiguity and would seem to require TOPs & GOs to agree on which generators are "material to" the blackstart plan. R2 is designated as a Long-Term Planning standard, but appears to allow coordination within 90 days following the implementation of setting changes. The phrase "Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1," is not clear. R1 requires coordination at least once every five years. R2 should require coordination before implementation of system, equipment, or setting changes, not within 90 days after.
Group
pacificorp
ryan millard
Yes
Yes
Individual
PSEG
Yes
Yes
We voted "Negative" on this standard the reasons shown below: This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1. 1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments: "The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree) states "Synchronous condensers are not currently addressed in the NERC Registry Criteria" However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency." The SDT responded as follows: "The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model." In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses: MOD-025-1: "The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2." PRC-019-1: "The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers." We need to see "one" statement from the SDT on the inclusion or exclusion of synchronous condensers that makes

sense technically, and soon. 2.No reliability benefit has been demonstrated for having the coordination review required by R1 done every five years. We suggest that the R1 be modified so that it’s clear that the entities must “verify” coordination upon the effective date ONLY, but not every 5 years thereafter. The effective date Section 5, part 5.1.1 states “By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.” Therefore, we suggest that R1 be rewritten as follows: “BY ITS EFFECTIVE DATE IN SECTION 5, each Generator Owner and Transmission Owner with applicable Facilities shall VERIFY the COORDINATION OF the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions.”
Individual
Xcel Energy
Yes
Yes
Individual
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)
Yes
Yes
Ingleside Cogeneration LP agrees that the proper coordination between a generator’s voltage limiters, protective relay settings, and its stability limits can best assure its availability in response to transient conditions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them – as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed: 1) All requirements for recurring assessments (R1) must contain language that focuses on the strength of the validation process – not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action “in a manner that identifies, assesses, and corrects deficiencies”. Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed – even those not applicable to the facility. The CEA’s focus needs to be on the entity’s commitment to the validation effort, not the documentation. 2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected – leading to inconsistent interpretations of the drafting team’s original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative – not its administrative aspects.
Individual
American Transmission Company
Yes
Yes
Individual
American Electric Power
Yes
Yes

Individual
Wisconsin Electric Power Company
Yes
Yes
1. In R1.1.2, we suggest revising the sentence to : "The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage…". 2. In R1, there needs to be a way for entities to take credit for coordination studies done in the last 2 years prior to the effective date of this standard. 3. In R2, the 90 day requirement to document coordination following a change is not reasonable. It may not be possible to obtain the necessary information from equipment vendors in this timeframe. We suggest a time of 180 days for this requirement. 4. It is not clear how these requirements would be satisfied at wind farms. None of the example information in Section G Reference appears to be applicable to wind farm equipment. We suggest that wind resources be specifically exempted from this standard.
Individual
Independent Electricity System Operator
Yes
Yes
1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by: a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner…" b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner…". 2. The wording of R1 is confusing, since the required coordination shall be maintain all the time. We suggest a change of the wording as follows: the phrase "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls" should read "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall review the coordination of the voltage regulating system controls" ; Also, the phrase "1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily." should read" 1.1.1. The in-service voltage regulating control limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily."
Individual
New York Power Authority
Yes
Yes
This Standard does not bring added reliability for the Bulk Electric System; it only adds an administrative burden for the entities. NYPA in its current protection system relay settings process inherently takes into account a margin for a unit's in-service limiters as well as other typical performance parameters.
Group
Tennessee Valley Authority
Brandy Spraker
1. Reference, Examples of Coordination, page 7 of 11, bullets at the top of page 7, Recommend deleting the word "associated" in all of the applicable bullets. Justification is that the word "associated" is not needed in these bullets and it will make the bullets more crisp. 2. Standard, 4.2 Facilities, The unit size applicability for PRC-019-1 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027-1 (i.e. MOD-026-1 Draft, 4.2,

Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ... (including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ... (including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ... (including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) 3. Requirement R1, Recommend changing the periodicity of this verification as stated “At a maximum of every five calendar years, ... “ to a recommended verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, “6 calendar years.” Justification is to coordinate protective system relay testing during plant outages with the voltage regulating controls and protections testing that can be performed during outage shut-down or start-up sequences.
Group
Southern Company
Shammara Hasty
Yes
Yes
Please consider placing the applicable unit size for PRC-019 and MOD-025 equivalent to that specified by MOD-026 and MOD-027. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. We suggest striking “Convertor Overtemperature” from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. R2 specifies “perform the coordination” while M2 states “coordination review” – we believe that R2 should be changed to “review the coordination” R1 appears to have been written with evolving T&D systems in mind. It should be made clear that all that is required for a generation unit that has experienced no changes affecting the response in question is a review of the equipment state every 6 (six) years rather than requiring a new coordination study.
Group
FirstEnergy
Larry Raczkowski
Yes
Yes
Individual
Northeast Utilites
Yes
Yes
No Comments
Individual
Utility Services
Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Group
Dominion

Mike Garton
Yes
Yes
Group
seattle city light
paul haase
No
New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Individual
Omaha Public Power District
Yes
Yes
We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Individual
Liberty Electric Power LLC
Agree
NAGF
Individual
Snohomish County PUD No.1
Agree
Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Individual
Cogentrix Energy
1. R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, 2. It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1. 3. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. 4. The term “black start unit material” in applicability para. 4.2.4 (p.2) is not understood. We would object if the intent was to designate any unit that has the potential for black startcapable conversion, in addition to units that are presently black start resources. GOs would in this

case have to take on substantial burdens based on mere conjecture as to modifications that might (but probably would not) be made sometime in the future. 5. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in our possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. 6. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. 7. It is suggested to strike "Convertor Over temperature" from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not an element that can be coordinated. 8. R2 specifies "perform the coordination" while M2 states "coordination review" – we suggest that R2 be changed to "review the coordination"
Group
Florida Municipal Power Agency
Frank Gaffney
1) R1 can be misinterpreted to require a full-blown coordination study every 5 years even if nothing at the plant had changed. There should be a qualifier saying that past coordination studies are still valid if nothing has changed, but that at minimum a review is needed every 5 years to see if the existing coordination study is still valid. 2) A synchronous condenser can be owned by either a TO or GO. For instance, there are installation of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO who owns a synchronous condenser.
Group
Duke Energy
Greg Rowland
Yes
Yes
1) Section 1.1: Reword to clarify "normal" is describing the AVR control mode only. Also, SDT should consider mentioning weak system operating conditions are typically used when coordination with the SSSL. Suggested rewording: "Under steady-state system operating conditions, and assuming normal AVR control loop conditions, verify the following coordination items for each applicable Facility:" 2) Section 1.1.2: Strike this section, as it is outside the scope of this document. It appears to be mandating protection. PRC-019-1 should be focused on settings. 3) Page 7/11: (Reword 2nd paragraph) Examples of limits, limiters, protection which must be coordinated if employed include: 4) Page 7/11: Remove all the words "associated" in second paragraph. 5) Page 7/11: Remove section on SSSL calculation. Does not belong in standard, see references listed as needed. 6) The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. 7) The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. 8) Strike "Convertor Overtemperature" from this list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. 9) R2 specifies "perform the coordination" while M2 states "coordination review" – we believe that R2 and M2 should be consistent.
Individual
Indiana Municipal Power Agency
Agree
Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum for PRC-019.
Group
MEAG Power

E Scott Miller
Agree
Southern Company Services, Inc. - Gen
Individual
South Carolina Electric and Gas
Yes
Yes
Group
JEA
Thomas McElhinney
JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Individual
Ameren
Yes
No
(1)Although we prefer a % of Facilities approach, we can accept the R1 VSL revision with the stated time frames. (2)A time-based VSL does not align with the severity of failing to meet R2. The severity is primarily a function of the amount of on-line exposure. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. We request that for R2 the SDT replace the time-based (days late) with % of MWh during the period of violation to more properly account for aggregate impact and restate the R2 VSL as follows: (a)Lower VSL becomes ‘The Generator Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing from 0% to 5% of their total MWh generated during the violation period.’ This does require each unit to be coordinated. (b)Moderate VSL becomes ‘…more than 5% and less than 10%’ (c)High VSL becomes ‘…more than 10% and less than 15%’(d)Severe VSL becomes ‘… more than 15%’. (3)We request that the SDT insert ‘latter of’ before ‘identification or implementation’ in R2 VSL if the SDT does retain the time-based VSL format. Identification differs from implementation so clarity is needed if a violation does occur.
(1)R2 is unclear as written, please insert ‘latter of’ before ‘identification or implementation’ to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. (2)Attachment 1 Example appears to violate R1 1.1.2. Loss of Field Zone 2 trips before ‘operating conditions exceed equipment capabilities.’ On the other hand, it would certainly ‘limit the extent of damage when operating conditions exceed equipment capabilities or stability limits’ since it trips before either of them are reached. This example does show how specialized and complex this coordination is. Entities may have different margins, asset protection, and operating practices. We presume the SDT intends that the examples show ‘coordinated’ capabilities, controls, and protection. If not, the lack of coordination should be pointed out. (3)We request that the GVSDT make all the papers listed in the reference section of the standard readily available on the NERC website.
Individual
Exelon Corporation and its affiliates
Yes
Yes
Section D, "Compliance," Part 1.2, "Evidence Retention," (page 4 of 11) first paragraph is unnecessary and redundant since the retention periods specified are for a six year time period which would be the maximum time between compliance audits for a registered entity. Exelon suggests that this paragraph be deleted in its entirety.

Group
Luminant
Brenda Hampton
Yes
Yes
Luminant recommends that Requirement R1 and Measure M1 be revised to clarify that the coordination described in the text is not between the Generator Operator and Transmission Operator. R1 would be revised in the following manner, “At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service 1imiters and protection functions) with its applicable equipment capabilities and settings of the applicable Protection System devices and functions. 1.1. Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility”. Measure M1 would be altered in the same manner.
Individual
Texas Reliability Entity
Yes
Yes
1) Does the SDT foresee any conflicts between the proposed language in PRC-019-1 and the proposed setting limits in PRC-025-1, Generator Loadability? 2) The SDT may want to include a reference ANSI C50.13-2005 for proper coordination of the over/under excitation limiters with AVR, equipment capabilities, and loss-of-field, and other protective functions. 3) Measure M1: Evidence should also include documentation that actual settings for relays, AVRs, and limiters match the coordination study. 4) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is “directly connected” to the BES. Please consider reviewing the language to see if it should instead say “included in” the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not “directly connected” to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. 5) In general, the Protection System changes should be coordinated before energization (or re-energization) following a change. Is the 90 day time period in R2 consistent with the expectations of PRC-001?
Individual
City of Redding
Agree
SMUD/BANC
Individual
SMUD
SMUD strongly suggests the SDT align the proposed PRC standard with NERC’s current direction of migrating reliability standards to a Results Based Standards (RBS) and internal controls approach. This standard, along with all the other recent NERC PRC proposed standards, are vastly increasing the administrative effort by asking for more documentation of relay settings. For instance, in R1.1.2 – Is it really necessary to have a regulatory requirement for the GO to protect his own generator from damage? (Intentional Space.....) As an alternate approach, why not state that anytime a generator trips off by a protective function that must be set to coordinate with a limiter, the GO must demonstrate that the relay was set per this standard. That is, that the protective function did(emphasis added) coordinate with the limiters. If it is set correctly, there is no violation. If not, violation. This reduces the compliance burden significantly, but does not weaken the incentive to comply. Entities will want to ensure they set their relays per the standard because no one wants to cause an outage or get a violation. But no entity needs to spend time on pre-event, zero-defect, compliance documentation for all its units – only post event documentation is necessary for units that tripped. We feel this type of results based approach is a better choice for this standard.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery, NERC Reliability Compliance Coordinator

No
AECI does not believe R1 should exist as currently drafted, see below.
Yes
Applicability, Part 4.2.4, CHANGE: Remove this entire clause specific to Blackstart of units of any size, RATIONALE: AECI agrees with earlier Industry commenters that opposed the inclusion of these units and disagrees with the SDT's persistent inclusion. Inclusion of Blackstart units of any size, ultimately harms the grid reliability by imposing more regulatory-risk exposure upon them, such that our industry is already seeing many disappear from system restoration plans. With this trend left unchecked, and we are trying to piece our systems back together 10 years from now for whatever reason, the RCs will not even know that many of these viable units still exist. Many may have in fact been driven from existence by such well-intentioned laws having failed to consider the unintended consequences. In addition, the value of AVR functionality for Blackstart units is highly questionable during blackstart situations. Requirement R1, CHANGE: Redraft the language toward each responsible entity's internal controls program, RATIONALE: While AECI appreciates the initial 5-year time-line to "check the coordination of all our unit's in-service limiting "stuff", we see the R1 5-year revisit of no added value. This is in contrast to the value of R2's invoking the correct triggering mechanism for events that would precipitate rechecking such protective systems and setting's coordination. AECI simply believes R1 to be overly prescriptive and its existence, as currently drafted, will destine it for future removal.
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
Yes
Yes
(1) R1 should be modified to clarify that the GO or TO shall coordinate their applicable Facilities. While most readers would interpret the requirement to apply to the Facilities owned by the GO and TO, it simply does not say this. We recommend using "each GO and TO shall coordinate the voltage regulating system controls … applicable equipment capabilities of its applicable Facilities and the settings of the applicable Protection System devices and functions." (2) While we disagree with the inclusion of blackstart units in this standard, the previous wording was actually more correct and consistent with the Statement of Compliance Registry Criteria. Changing "Blackstart Resource" to "blackstart unit" only causes confusion and ambiguity. By definition a "Blackstart Resource" is a blackstart unit that is included in the Transmission Operator's restoration plan. Since the applicability section also states that the blackstart unit must be included in the TOP's restoration plan, it is not clear what was accomplished with changing Blackstart Resource to blackstart unit. It causes the reader to question what additional units are intended if they don't mean Blackstart Resource. Furthermore, it deviates from the wording in the Statement of Compliance Registry Criteria. This is contrary to the response that was provided to a comment by PSEG to change the language during the last posting. The response indicated that the "SDT feels it is best to retain the NERC wording without modification." We can find no other citation in the response to comments indicating a reason to change it. Please change blackstart unit back to Blackstart Resource. (3) In applicability sections 4.2.1 through 4.2.3, please change "directly connected to the BES" to "that are part of the BES". Per the BES definition, generation units can be and are part of the BES. Using "directly connected to the BES" could draw in a non-BES unit. (4) There is an extraneous comma in R2.
Individual
Brazos Electric Power Cooperative, Inc.
Agree
ACES Power Marketing
Individual
Cowlitz PUD
No
Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
No
Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Cowlitz supports the review performed by the NAGF SRT with modification: 1. Requirement R1 appears to have been written with ever-evolving T&D systems with multiple owners/planners in play where Protection System settings may require adjustment to assure proper operation. However, this is not the case for generation facilities

which remain relatively static under single management until system improvements are made. Further, it is unprecedented to require a scheduled reassessment of system control settings without cause. The Standard Requirement R1 appears to assume it necessary to review past coordination engineering work and resulting system control and Protection System settings for errors every five calendar years. We see no reliability return in such activity. Requirement R1 must be centered on first establishing that proper coordination engineering and resulting system control and Protection System settings have been completed, and documentation of such work is retained in a Generation Facility Control and Protection Manual. Requirement R2 then covers the cause for review – system improvements, equipment upgrades, new operation theory, etc. – that triggers a reassessment of the coordination engineering and if necessary a revision to the Generation Facility Control and Protection Manual. The only possible item that may merit a scheduled activity is to verify all settings have not inadvertently changed, and are in compliance with the current Generation Facility Control and Protection Manual. 2. The nonexclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. 3. The term "black start unit material" in applicability para. 4.2.4 (p.2) should be changed to the NERC defined term Blackstart Resource. Further, (departing from NAGF SRT Comments with suggested SDT response) it must be understood that Blackstart Resources must involve coordination between the TOP and the GOP. The TOP is not allowed to unilaterally designate blackstart capable resources within their restoration plan. EOP-005-2 mandates this via Requirement R13.
Individual
Nebraska Public Power District
Agree
MRO NSRF