Individual or group. (28 Responses)
Name (17 Responses)
Organization (17 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Question 1 (25 Responses)
Question 1 Comments (28 Responses)
Question 2 (0 Responses)
Question 2 Comments (28 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Individual
Thad Ness
American Electric Power
Yes
AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4, thereby making the timing requirements of the standard more consistent throughout. R2: Regarding the language “If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying”, we believe the intent is to allow the GO to set its protective relaying within the PRC-024 no-trip zone and remain compliant so long as the Transmission Planner’s less stringent requirements is met. However it is not made explicitly clear by doing so that one would still be fully compliant with PRC-024. We recommend making this explicitly clear within R2. Suggest rewording the first sentence of R2 to state the following: “Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) that remains within the “no trip zone” of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant.”
Individual
Nazra Gladu
Manitoba Hydro
Yes
(1) R2 – are the words ‘the applicable generating units’ missing after the word ‘trip’ in the third

line? this would make the language consistent with the wording of R1. (2) R2- are the words ‘of a location specific Transmission Planner’s study’ precise enough to know for certain what characteristics are being referred to and compliance measured? (3) R3 – is the word ‘known’ precise enough to know for certain what characteristics are being referred to and compliance measured? (4) R3, 3.1 – there is no notification requirement with respect to any modifications or upgrades that may remove the limitation – this seems to be a gap. (5) M3 – the word ‘documentation’ should be changed to ‘information’. (6) M4 – does not seem to track the wording of R4 – measure should be that it ‘provided applicable generator protection trip settings’…….and the word ‘information’ should be ‘data’. (7) Compliance – same comment as previous re: use of the acronym CEA. (8) VSLs, R1 and R2 – the way these requirements are worded it makes it seem as though the violation is that the GO has no documented limitation – that is not the violation, that would be a violation of R3. The violation for these two requirements would be a failure to set its relaying within the criteria of R1/R2. (9) VSLs, R2 – doesn’t contemplate new change to language of R2 re: TP standards. (10) VSLs, R3 – the timeline doesn’t address any change other than the identification of the limitation, i.e. but the timeline could run from repair, replacement. (11) VSLs, R4 – some refer to a ‘written request’ and some refer to a ‘written request for the data’ – these should be made consistent with the requirement language.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Group
PacifiCorp
Ryan Millard
Yes
Individual
Daniela Hammons
CenterPoint Energy
CenterPoint Energy remains concerned with truncating the Voltage Ride-Through Time Duration Curve (Attachment 2) at 4 seconds due to coordination with undervoltage load shedding systems (UVLS). For coordination of UVLS with any generator voltage protective relays, CenterPoint Energy recommends the curve be extended to at least 10 seconds at 0.90 per unit POI Voltage. CenterPoint Energy does not believe such a change would be controversial, as the GVSDT states in the Consideration of Comments (Draft 5) that “Stakeholders pointed out that transmission systems are designed to operate between 90% to

110%."
Group
Detroit Edison
Kent Kujala
Yes
Regarding Footnote 1 for R1, are protective functions within control systems that measure frequency from a non-electrical input such as speed sensors, included as "protective relaying"? Please clarify that this standard pertains only to generator protective functions that respond exclusively to voltage and/or frequency, but not current. Please adjust Attachment 1 Eastern Interconnection frequency data point exponents on page 13 so that they are completely visible. Please verify for Attachment 2 Voltage Curve that continuous operation is expected greater than 0.90 pu. and less than 1.10 pu.
Individual
Bill Fowler
City of Tallahassee
Yes
No
Group
Duke Energy
Greg Rowland
Yes
No
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
No
R4 as it was rewritten in draft 6 seems like a redundant sub requirement of PRC-001 R3. The type of protection described in R2 and R3 falls already in the "coordination" required category described in the NERC Technical Reference Document, "Power Plant and Transmission System Protection Coordination" Revision 1 – July 2010 http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf Furthermore the requirement fails to specify the accountability and responsibilities of the Transmission Planner/Transmission Operator in the "coordination" process in order to approve the relay setting changes. R4 should be eliminated or merged into PRC-001 R3 to avoid redundancies per FERC's instructions on eliminating redundancies.
PRC-024-1 previous draft placed the burden of complying with the standard solely on the GO.

This new draft places the bulk of ensuring compliance on the GO while providing a different criteria or “exemption” given by the Transmission Planner. If that is the case, the Planner should have a joint obligation to ensure the GO/GOP is successful in meeting and achieving compliance spelled out in the standard. Additionally, the Planner would be the best party capable of determining “which voltage protective relaying setting does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. Applicability of the standard should also include the Transmission Planner. R2 also lacks a mechanism(how the study is initiated and why, study request timeframe, study response timeframe, etc) whereby the Transmission Planner provides the “less stringent” voltage protection requirements so the GO can then determine when they need to follow Attachment 2 or the Planner’s study or have the Planner determine the criteria first. The requirement should be clearer and more details should be added. R3 objectives state that the GO shall provide equipment limitations to the Planner within 30 days of a request or change. PRC-024-1 R3 does not provide any value when MOD-010, MOD-012 and MOD-025, MOD-026 and MOD-027 appear to address these issues. R3 needs to be clarified with more details to avoid possible redundancies with the MOD standards.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
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
Pamela R. Hunter
Yes
Individual
John Seelke
Public Service Enterprise Group
Yes
Yes. For generators without frequency or voltage protective relaying, R1 and R2 respectively do not require these relays to be installed per footnote 1. However, R3 could be interpreted to require generators without such relaying to be required to comply with R3 because it applies to a generator limitation that “prevents an applicable generating unit from meeting the relay

setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice." We have received an e-mail from the drafting team NERC coordinator for this project that this is NOT the intent of R3 – R3 is only intended to apply to generators that HAVE frequency and/or voltage protective relaying installed. We ask that the SDT confirm this understanding. If this is the SDT's intent we recommend that R3 be clarified as follows: Each Generator Owner shall document each known regulatory or equipment limitation3 that prevents an applicable generating unit WITH GENERATOR FREQUENCY OR VOLTAGE PROTECTIVE RELAYS from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advice. Alternative wording to clarify R3's intent that it does not apply to generators witout frequency or voltage protective relaying would be acceptable.
Group
Luminant
Brenda Hampton
Yes
Individual
Chang G. Choi
City of Tacoma, Tacoma Public Utilities, Tacoma Power
Yes
It is not completely clear how to implement Requirement R2 given the information contained in Attachment 2. Specifically, clarification is requested on the following two issues. A. In Attachment 2, what issue is Curve Detail 3 intended to address? Is it suggesting that definite-time voltage elements should be used, instead of inverse time elements, unless detailed analysis is performed? It is not clear if Curve Detail 3 is intended to afford entities additional flexibility or to require them to conduct more detailed analysis. B. In Attachment 2, is the section titled "Evaluating Protective Relay Settings" intended to determine the per unit voltage base, at the generator terminals, for the Voltage Ride-Through Time Duration Curve? Under Measurement M3, change "manufacturer's advisory" to "manufacturer's advice" to be consistent with Requirement R3. In Attachments 1 and 2, do the "no trip zones" include the lines? In other words, for the Western Interconnection, if a frequency element was set to 57.2 Hz, would an operating time of 0.75 seconds be acceptable per the standard, or does the operating time have to be above 0.75 seconds? (A similar question could be asked for the Voltage Ride-Through Time Duration Curve.) In Attachment 2, under "Evaluating Protective Relay Settings," change "use either the following…" to "use either of the following…"
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Yes

FOR: Requirement R1, REPLACE: "the frequency protective relaying" WITH: "that generator frequency protective relaying" RATIONALE: SDT intent, with the subordinate bulleted exceptions, appears to provide for exception of necessary overriding conditions within the "no trip zone" for which the "generator frequency protective relaying" is permitted to necessarily go ahead an trip the unit. This suggested change is an attempt to strengthen the linkage between the qualifying R1 "has generator frequency protective relaying activated...", and those bulleted exceptions in order to calm industry concern that those bullets form the only permissible set of unit protective relaying conditions that are allowed to trip the trip (protect) the unit and its underlying equipment when operating within the units' "no trip zone" of frequency conditions. FOR: Requirement R2 REPLACE: "the voltage protective relaying" WITH: "that generator voltage protective relaying" RATIONALE: Basically the same as outlined for the suggested R1 change above, but for voltage rather than frequency. FOR: Appendix 2 (graph) CHANGE: (raise the graph's 0 pu for 0.15 sec) TO: (15 pu for 0.15 sec, along with an appropriate footnote for consideration of preexisting equipment capability) RATIONALE: While the SDT cites FERC ORDER 661A and Appendix G in support of this value, FERC's paragraph 31 ruling agrees with NERC's proposed considerations they earlier discussed. NERC's proposal includes consideration for earlier-purchased wind turbines and their voltage ride-through capabilities, as well as provision for NERC to use their normal process to revise the ride-through capability. AECI believes the SDT should work to build industry consensus on an overall minimum voltage ride-through, or at least afford our industry the same considerations cited for wind turbines.
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Yes
Group
Dominion
Mike Garton
Yes
Individual
David Jendras
Ameren
Yes
(1)On page 8, please delete “Measure M1 through M4” from the second paragraph of D.1.2 Data Retention. We understand that the entity must comply with the Requirements but the

Measures should not expand the scope of reliability standard requirements. (2)We request that the GVSDT add page numbers in the footer of the standard.
Individual
Karen Webb
City of Tallahassee
Yes
No
Individual
Scott Langston
City of Tallahassee
Yes
Individual
Darryl Curtis
Oncor Electric Delivery Company
N/A
The 60 calendar day requirement in R4 requiring a Generator Owner to provide its applicable generator protection trip settings to the Planning Coordinator or Transmission Planner within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings is too long. Settings that affect the performance of a system need to be communicated as quickly as possible and because of the critical nature of this data, prolonging system coordination could result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor respectfully requests this time requirement be shortened to 30 days.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration agrees with the removal of R4. Our experience has been that ambiguities in reliability requirements force Compliance Enforcement Authorities to provide their own interpretations. This may result in uneven enforcement of the criteria or the development of a Compliance Application Notice, neither of which instill a sense of fairness in the process. Our hope is that the industry develop its own methods to predict voltage and frequency ride-through performance – which would be voluntary and supported by NERC experts.
Ingleside Cogeneration would like to point out that there are already 30 in-effect PRC and MOD standards – with at least four other project teams actively developing new modeling and Protection System requirements. In almost every case, the reliability intent is to ensure that

interconnected entities openly share relay settings, models, and operating information that reduces the risk to the greater whole. However, we do not believe that there is compelling evidence that adherence to these reliability standards correlates to improved reliability – therefore, the addition of one more PRC standard will not reduce BES risk. It is time to consider a more effective regulatory model to address generation/transmission coordination – one that recognizes that the subject matter is extraordinarily complex, with nearly more exceptions than commonalities. The focus would move from the enforcement of global mandates which do not always apply, to ensuring that GOs, PCs, and TPs are continually working the tradeoffs between BES stability and the threat to equipment damage. In this venue, NERC could serve as an expert arbiter to help resolve differences – a role that we believe will lead to the structural improvements necessary to reach our shared reliability goals.
Individual
Brett Holland
Kansas City Power & Light
Yes
This standard should apply to voltage protection and frequency protection only. It should not apply to volts/hertz or other generator protective elements. Volts/Hertz is specifically intended to protect transformers and generators from damage and the setting is based on the capability of those elements. The SDT has given guidance on Evaluating Protective Relay Settings however this creates a situation where protective settings might appear to be in conflict with the standard and during an audit a study or documentation must be presented to prove the relay setting on the generator side of the GSU is actually in compliance with the standard on the transmission side of the GSU based on the study documentation. Standard Requirements should be straight forward so compliance can be proved with the least amount of effort and documentation. The SDT should use the guidance on Evaluating Protective Relay Settings and produce Voltage Ride Through Time Duration curves on the generator side of the GSU because that is where the voltage source is for the existing generator protective relays.
Group
ACES Standard Collaborators
Jason Marshall
Yes
(1) We continue to be concerned that this standard is inconsistent with the stated vision of NERC regarding the transformation of the compliance process. As the standard is written, it has the potential to become another zero-defect standard in which compliance is paper driven and does little to support reliability. Because plants have lots of equipment, how will the auditor know that frequency and protective relay settings have been set according to the standard without first ensuring they have identified the appropriate relays to review? We can envision them wanting to see the list of all protective relays so that they can first verify that all voltage and frequency relays have been identified and then the list of settings based on this subset.

Furthermore, the language of the standard concerns us that a registered entity will be expected to provide evidence for any unit that trips to prove that it did not trip because of frequency or voltage protective relaying if the voltage and frequency remained within the associated envelopes of performance in the standard. (2) We are concerned that compliance with the standard will be inappropriately enforced based on the actual performance of a unit. The purpose statement says that the generator should “remain connected during frequency and voltage excursions”. Based on this purpose, we would be concerned that compliance with the standard would be assessed based on whether the generator rode through voltage and frequency excursions within the performance envelopes defined in the standard. This would be an inappropriate outcome because the requirements in the standard compel relay settings based on assumptions stated in the “Evaluating Protective Relay Settings” section of Attachment 2. If system conditions did not match the assumptions, how could the GO be held accountable? We believe that standard should make crystal clear that compliance is not to be assessed on actual performance because no GO can guarantee its units will ride through all voltage and frequency excursions defined in the performance envelope in the standard if the conditions vary from the assumptions. While we understand the drafting team did attempt to clarify this with a modification to the “Evaluating Protective Relay Settings” section in Attachment 2, the clarification is not enough. It only makes a statement about the assumptions to be used not how compliance should be assessed. We suggest application guidelines should be written to clearly describe how compliance would be met. We also suggest that an RSAW be developed to allow industry to provide feedback on compliance concerns. Finally, we recommend that the VSLs be modified to address these compliance concerns and to ensure consistency throughout the standard. (3) We continue to believe that requirements R3 and R4 are the types of requirements that the P81 project is attempting to retire. Both of these requirements fit more than one criteria in the project. Both are communication and documentation requirements and do little to support reliability by themselves. While we agree the GO needs to communicate equipment limitations, this type of requirement is administrative in nature and results in excessive paperwork burdens that NERC will monitor and enforce using a zero defect methodology. If it was necessary to have a requirement for every detail that needs to occur to plan and operate the electric grid, we would have millions of requirements. Part of the reason for these P81 criteria is to avoid the need to monitor compliance for every little detail like this. Furthermore, the VSLs associated with both requirements demonstrate that the requirements do little to support reliability. They anticipate the only violation is that compliance will be late. There are other options and alternatives that NERC and the Regions could utilize to ensure that the GO is communicating equipment limitations. At this point, we do not believe the drafting team has provided enough technical support to justify this type of requirement. (4) We continue to believe that the data retention period is too long and may cover time periods that include prior relay settings that are no longer relevant. What reliability benefit is provided by a Generator Owner retaining settings that are no longer valid? The proposed language compels the GO to retain data for six years which means that a GO may have retained evidence for settings that are no longer used. While the drafting team indicated that it used NERC boilerplate language in establishing the data retention period, there is nothing that requires the drafting team to use this language

requiring the data retention period to match the audit period. In contradiction, section 3.1.4.2 of Appendix 4C- Compliance Monitoring and Enforcement Program of the NERC Rules of Procedure is very clear that reliability standards may have a data retention period that is less than the audit period. Furthermore, countless standards use other data retention periods where it makes sense. For example, TOP-003-2 uses 90 days for one of the requirements based on the sheer volume of the data. The bottom line question should be: “Does a six year data retention period and the associated resources dedicating to maintaining this data for that long support reliability?” The answer is no and, thus, it should be changed. We recommend the data retention state that only the current relay settings should be retained. (5) The VSLs for R1 and R2 do not anticipate the situation where there is no equipment or regulatory limits. This could be remedied by making “and” into “and/or” in the VSLs. (6) Thank you for the opportunity to comment.
Group
Bonneville Power Administration
Jamison Dye
Yes
Individual
Bret Galbraith
Seminole Electric
The proposed PRC-024-1 Attachment 1 “Off Nominal Frequency Capability Curve” lists a table and plots a “No Trip Zone” for the Eastern Interconnection that inherently includes the FRCC Region. Currently, the FRCC Region has its own Generator Coordination Requirements document that sets out frequency capability curves that conflict with what is stated in Attachment 1 for the Eastern Interconnection. Seminole believes that Attachment 1 should take into consideration the specific frequency trip settings that the FRCC has listed in the FRCC’s internal compliance handbook, which can easily be submitted to NERC (if NERC does not already have access to this information). Requiring the FRCC to abide by these general Eastern Interconnection frequency trip settings may cause instability to the FRCC Region due to the FRCC’s peninsular geography, and therefore, Seminole reasons that a specific frequency capability curve, i.e., “no trip zone,” should be designated for the FRCC Region. In addition, underfrequency relays have been applied for years with a frequency setting and a timer for each setting, to provide for a step, piecewise underfrequency shedding plan. The proposed NERC frequency chart uses a linear characteristic with multiple frequencies and multiple differing times. Even the best available technology today does not support the NERC linear frequency chart.
Individual
Spencer Tacke
Modesto Irrigation District

No
I think adding the word “applicable” before the word “generator”, without defining applicable, is irresponsible and will lead to more confusion. I think in this case the word “applicable” may be being used as synonymous with the word “significant”. WECC requires dynamic model verification for all units 20 MVA or larger connected at voltages 60 kV and above. This is because WECC members have learned over the years learned to recognize the significant role that smaller size generators play in system response and stability. Also, the WECC MVWG (Modeling and Validation Work Group) is currently performing a study to determine what is the minimum size generator for which model testing and verification needs to be completed. Also, within the next few years, there will be thousands of MWs of PV solar plants on-line in Central California, a large percentage of which will be small, 20 MW plants. We see about 2,500 MW of 20 MW PV units in the queue for the SGIP, SGIP-TC, WDAT, Clusters 1&2, and Clusters 3&4 in California, all coming on-line between now and 2017. Also, past WECC studies over the years of major outages have shown that generators, and indeed loads, below 100 kV, have played a major role in the impact of outages. In fact, the most accurate duplication of the 1996 outage and more recent outages that the WECC MVWG has simulated, have shown that the accuracy of the simulated results of actual system outages is highly affected by the accuracy of the modeled system below 100 kV. So I think it is very important to define what an “applicable” generator is for this standard, and I would recommend any generator 20 MVA or greater, connected at 60 kV or above.