NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date: 7/25/2017
Comment Period End Date: 9/8/2017

There were 43 sets of responses, including comments from approximately 127 different people from approximately 96 companies representing the 10 Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Summary Consideration

The vast majority of stakeholders were supportive of the revisions. There were a number of clarifying suggestions that the standard drafting team (SDT) incorporated into the documents, but more importantly the SDT revised the Implementation Plan to allow for phased-in effective dates.

The SDT made a minor revision in Option 5b to improve clarity based on stakeholder comment. A footnote was added to the Applicability section to bring attention that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." The SDT revised Figure A based on comments and added a new Figure 4 in the Application Guidelines to illustrate Elements utilized in the aggregation of dispersed power producing resources (e.g., collector

system or feeders). The relay location information in the Relay Type column of Table 1 was moved to the Application column to make the table content more consistent with the text in each column. There were no justification changes to the VRF/VSL Justification when the SDT updated the document to the new NERC template.

The Implementation Plan was revised so that the PRC-025-2 Implementation Plan will supersede the PRC-025-1 Implementation Plan. The intent is to prevent instances of non-compliance under Table 1 Option 5 of PRC-025-1 that could result in self-reporting while not unreasonably extending the original effective dates. The Table 1 Options that now include the 50 element will have phased-in dates that occur 60 months for setting changes and 84 months for equipment replacement or removal after approval. Other minor revisions in the Table 1 Options as outlined in the Implementation Plan will have phased-in dates that occur at 24 and 48 months likewise.

The Application Guidelines were not removed from the standard. The separation of the Application Guidelines from the standard is anticipated to be done under a later NERC project focused on addressing standards containing forms of implementation guidance.

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Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

4. Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

8. Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

9. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

10. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.

11. Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.

12. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Ryan Strom	Buckeye Power, Inc.	4	RF
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Con-Edison	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Québec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Québec	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

Question 1	
1. *Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.*	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
More clarity is needed on the implementation of Option 5b. "Resource capability" should be defined such that this value can be clearly determined. A detailed example for Option 5b which uses a plot similar to Figure A that discusses "documented tolerances" would be helpful.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Resource capabilities do not have tolerances associated with them.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The overcurrent element setting of 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor is appropriate in most cases. Texas RE recommends keeping the 130% threshold for overcurrent elements and allow for exceptions in those cases where entities are limited by manufacturer requirements or physical limitations.	

Question 1	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5b is essentially an exception based option for inverter based machines that cannot achieve the 130% threshold due to equipment limitations.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solar facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 1	
Option 5b is helpful and a clear improvement. In addition, Reclamation recommends that Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the generator will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement. Or, as approved in PRC-024-2, if Option 5 cannot be satisfied for older equipment, a statement such as, "Document the identification of regulatory or equipment limitations."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.	
Likes 0	
Dislikes 0	
Response	

Question 1	
Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
What is the need for option 5a with 5b being an option? Option 5b shows the correct way protective relays should be set and coordinated with equipement. If the protection can be set above the capability of the equipement output, what would be the reason to set the pickups at 130% above MVA unless you want a fault to cause more damage to the equipement being the clearing time could be delayed?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Option 5a was left to allow entities that have implemented to continue using the option. The options provide a minimum thresholds to set load-responsive protective relays for depressed voltages based upon 0.85 per unit nominal voltage. The standard is not addressing protection for longer periods that would protect against sustained low voltage or over loading.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group has a concern that Figure A (page 32 redline version) doesn't provide enough clarity on its purpose in reference to Option 5b. Additionally, we have a concern that the figure is missing the appropriate labeling methodology. We would ask	

Question 1	
the drafting team to provide more clarity in the Application Guideline Section of the Standard in reference to the figure's significance to Option 5b as well as including the appropriate labeling methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Figure A and the Table 1, Option 5b, Setting Criteria to be consistent.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends the SDT use the same frame of reference for both the Option 5a in Table 1 and Figure A. As currently written, Table 1 states "The overcurrent element shall not infringe upon…" while Figure A states "Option 5b – Resource capability shall not infringe on…".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Figure A and the Table 1, Option 5b, Setting Criteria to be consistent.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG is of the opinion that there is a discrepancy between the Relay setting criteria description for option 5b in Table 1 and the description contain in the Figure A, which should be corrected. Instead of "Option 5b – Resource Capability shall not infringe on the lower	

Question 1	
tolerance of the protective device" we recommend Figure A should state the following "Option 5b – Protective device overcurrent element settings lower tolerance tripping characteristic shall not infringe on the Resource capability" Additional clarification is required regarding if asynchronous resource capability accounts for forcing & boosting effects on the steady state fault current (not the subtransient and transient).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team modified Table 1, Option 5b, Setting Criteria similar to the suggestion in the comment. The last comment is out of scope of the standard because the capability corresponds to 1.0 per unit voltage.	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it's protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Equipment limitations for other applications in Table 1 have not been identified by industry.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Question 1	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 1	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 1	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	

Question 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 1	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	

Question 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 1	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes

Question 1	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Not applicable to BPA.	
Likes 0	

Question 1	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Question 2	
2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instantaneous) as well as low voltage trip designations commonly referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses. If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard.	

Question 2	
The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.” Individual generator control systems are outside the scope of the drafting team’s revisions.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but “pickup” was struck and Option 5 refers to overcurrent elements. Where the standard refers to “elements,” Reclamation recommends the drafting team insert the words “PRC-025 relay” to clearly state that only PRC-025 relays are applicable, not control systems, protective algorithms, or fuses. If the drafting team meant to include more protective elements than relays, Reclamation recommends that the standard clearly state the applicable protective elements. This standard is written to zero-defect and subject matter experts must clearly understand where it does and does not apply. Unless the standard allows some room for a small amount of error to be corrected, the compliance thresholds must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding “element” and “relay” to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.”	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Question 2	
Answer	No
Document Name	
Comment	
The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to “elements” please add the word “PRC-025 relay” in front to clearly state that only “PRC-025 relays” are applicable, not control systems, not protective algorithms, and not fuses. If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team had already revised locations regarding “element” and “relay” to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.”	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

Question 2	
67 and 50 elements/relays should be out of scope due to the possibility of creating a protection sheme that may not pick up when it should. See comments from Exelon.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 67 and 50 elements should be in scope as they can be susceptible to tripping under certain loadability conditions. Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

With respect to phase directional instantaneous overcurrent supervisory elements (67 or 50) – associated with current-based communication protection systems please consider the following

1. These relays will be affecting loading/generator loadability only if communication system fail and there is a disturbance on the grid. The Standard should not assume both events at the same time.

2. Calculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element.

Question 2	
3. Exelon proposes the following changes: i. These types of relays (67 or 50) should be deleted from the scope of this Standard for the reasons described above. ii. If there is an issue with communication protection systems such that the pilot protection scheme acts like a simple overcurrent relay, and that condition is alarmed, then it is reasonable to require an entity to correct this condition within a short period of time. Suggest the SDT add a requirement to correct such a condition within a certain timeframe. For example the condition shall be corrected within a calendar quarter and if not resolved then the setpoints of 67 or 50 should be raised to a certain value. iii. If SDT still wants to keep these relays within scope in spite of the reasoning/alternatives provided above, the the existing setting criteria the following should be added: "Minimum of the criteria 15a (or 15b) or 25% of the sub-transient current contribution from the generator using a pre-fault voltage of 1.0 and generator sub-transient unsaturated reactance and the main power transformer positive sequence reactance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. Based on the drafting team's experience, a communication system failure could last for an extended period of time. This will increase the possibility that a disturbance could occur during the communication failure. 2. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[1] Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	

[11] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 2	
3. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[2]	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Unfortunately, the addition of "e.g." does not add clarity. The SDT needs to clearly state what protection function each option in Table 1 applies to.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team provided this change to allow a level of technology neutrality on IEEE/ANSI device numbering. For example, for the 51 V-R relay the Application Guidelines note that these protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

[22] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 2	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 2	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 2	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	

Question 2	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 2	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 2	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 2	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 2	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Question 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 2	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes

Question 2	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
3. ***Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.***	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Question 3	
Answer	No
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term “Element” which specifically excludes collector systems via NERC and industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85. Link: http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf Please state that Technical Guidance is for examples only, guidance isn’t enforceable and cannot alter the scope of compliance. See attached document for diagrams.	
Likes 1	Jeffrey Watkins, N/A, Watkins Jeffrey
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the “collector system configuration” is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator’s system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The Guidelines and Technical Basis will be evaluated by NERC for removal from the standard and for placement in a separate document under a Standards department project.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No

Question 3	
Document Name	
Comment	
Figure 3 of the Guidelines and Technical Basis section discusses the inclusion of collector system protective elements; however, the NERC defined term “Element” specifically excludes collector systems in accordance with the NERC bulk Electric System Definition Reference Document dated April 2014; see page 21 of 85. http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf Reclamation recommends that the Guidelines and Technical Basis document state that it is an example only and is not enforceable, or remove the discussion on collector system protection elements. If the drafting team intended to include collector system protective elements for zero-defect compliance monitoring and change management, Reclamation recommends the standard be revised to clearly state “PRC-025 collector system” or “PRC-025 collector system relay elements” throughout the standard, including the Applicability Section.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the “collector system configuration” is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator’s system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of “Element” (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition. The Guidelines and Technical Basis will be evaluated by NERC for removal from the standard and for placement in a separate document under a Standards department project.	

Question 3	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[3]	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and industry agreement in 2014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.	

[33] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 3	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
It is an improvement and adds additional clarity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Question 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 3	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes

Question 3	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 3	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	

Question 3	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Question 3	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 3	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	

Question 3	
Likes 0	
Dislikes 0	
Response	

Question 4	
4. *Do you agree that the proposed revisions in Table 1 for Options 14 through 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.*	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The settings should not inhibit the output of the generator for the conditions anticipated by the standard and should be properly set to provide adequate fault protection of the respective equipment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Question 4	
No because if you have multiple radial lines exporting the power from a generator, each line may not have the capability of carry the full power output of the generator. Engineers should have the ability to study individual installations and set the protection correctly for the equipment installed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The issue of multiple lines leaving a plant is addressed in the existing and proposed standard under the heading “Multiple Lines” in PRC-025-2 – Attachment 1: Relay Settings.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any revisions proposed that would require an entity to re-perform calculations in order to become compliant with the standard.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	

Question 4	
Comment	
Tri-State would like clarification on the phrase "and on the remote end of the line" used in the Relay Type column of Option 14. Looking at the red-lined language under "Figure 1" of the guidelines section, our understanding is that relay R3 is applicable only if it is set with an element directional toward the transmission system or is non-directional. If relay R3 is set directed toward the generator, it is not applicable. If that is the case we recommend splitting up the language between the 2 scenarios and adding a figure to make it clear. As it is currently written, it isn't clear that only the 1st of those scenarios is displayed in Figure 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team does not agree the suggestion to split the example into a second Figure would add clarity.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be “grandfathered” for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any revisions proposed that would require an entity to re-perform calculations in order to become compliant with the standard.	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	

Question 4	
Answer	No
Document Name	
Comment	
While it is not typical for a generator to be rated higher than the line connecting the GSU to the transmission system, PSE has concerns with setting the relays for the line based on the generator ratings. Protective relays should be set according to the equipment that they are intended to protect (i.e. line relays should be set to protect the line, transformer relays should be set to protect the transformer, and generator relays should be set to protect the generator). Setting a line relay to protect a generator, particularly when the line might be rated lower than the generator could result in damage to the line, and could potentially result in reduced reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The settings should not inhibit the output of the generator for the conditions anticipated by the standard and should be properly set to provide adequate fault protection of the respective equipment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
This sentence is confusing: “Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing” Consider changing to: “Simulated line voltage at the relay location coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing”???	
Likes 0	
Dislikes 0	

Question 4	
Response	
Thank you for your comment. The drafting team applied the suggestion to Options 14b, 15b, and 16b.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes

Question 4	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 4	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	

Question 4	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 4	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	

Question 4	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 4	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 4	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 4	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Question 4	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	

Question 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	

Question 4	
Likes 0	
Dislikes 0	
Response	

Question 5	
5. ***Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.***	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
The term "pickup" clearly indicates what part of the overcurrent device setting needs to meet the criteria. Perhaps this term can be retained for current operated devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of "Pickup" from the standard as scoped in the SAR and agrees that "Settings Criteria" is a more appropriate term for the value. It aligns with the intent of the standard for relays to not trip based on the criteria in Table 1.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
"Pickup" setting indicates the minimum operating value. Please retain the leading term "Pickup".	
Likes 0	

Question 5	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.”	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Question 5	
Answer	No
Document Name	
Comment	

If Pickup is not removed:

Reclamation recommends the SDT provide clarifying language describing what removing “Pickup” means. Pickup for PRC-025 refers to “PRC-025 Relays,” meaning actual relays at the individual generators with pickup settings. This does not include 1) any individual generator control systems, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

If Pickup is removed:

Reclamation recommends the SDT decide what protective relays are to be included and explicitly specify them. The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drafting team is looking for protective elements in addition to relays. If the SDT intends to include more than PRC-025 protective relays, the applicability criteria must be adjusted in addition to removing “Pickup.”

Reclamation recommends the PRC-025 Applicability section should specifically reference 1) individual generator control systems that may trip the individual power producing resource, 2) collector system protective relays that may be installed on the padmount transformers, or 3) collector system protective relays on the radial collectors at the collector substation.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.

Question 5	
The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.” On item (1) Individual generator control systems are outside the scope of the drafting team’s revisions, and items (2) and (3) they are already applicable per the Applicability section 4.2.5.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The applicability section states that PRC-025 applies to relays. Removing “Pickup” suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing “Pickup”. Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.”	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No

Question 5	
Document Name	
Comment	
The setting that has to be met per the standard is the pickup setting, the standard does not talk about timing, just pickup, so why remove pickup from the table.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team addressed the removal of “Pickup” from the standard as scoped in the SAR and agrees that “Settings Criteria” is a more appropriate term for the value. The use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to “not trip” based on the criteria in Table 1.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
It would provide added clarity to include “non-directional” in front of “phase instantaneous overcurrent supervising elements (e.g. 50)” and “phase time overcurrent relay (e.g. 51)”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The devices 50 and 51 are defined as non-directional elements. Further clarification would be redundant.	
Ruth Miller - Exelon - 5	

Question 5	
Answer	Yes
Document Name	
Comment	
See comments provided in the response to Question 2 above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. Based on the drafting team's experience, a communication system failure could last for an extended period of time. This will increase the possibility that a disturbance could occur during the communication failure. 2. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[4] Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection. The suggestion is beyond the scope of the drafting team's work to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[5]	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

[44] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

[55] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 5	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 5	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Question 5	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	

Question 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 5	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes

Question 5	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 5	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	

Question 5	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 5	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	

Question 5	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 5	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Question 5	
Texas RE noticed the term “Overcurrent Element Pick-up Tolerance” still exists in Attachment 1 Figure A. Is this the SDT’s intention?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This terminology is consistent with the IEEE C37.17-2012 standard.	

Question 6	
6. *Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.*	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
I do not agree with application of this standard. Protection should be set up and coordinated for individual installs not by generitc percentages above MVA nameplates. Setting criteria should not be enforced by NERC unless NERC is willing to take responsibility for any equipment damage from settings being set to high.	
Likes 0	
Dislikes 0	
Response	
Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 6	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	

Question 6	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 6	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	

Question 6	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement is not necessary, and (2) 36 months where equipment removal or replacement is necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
The 36 months may not be long enough to replace the relays depending on the number of relays that have been identified for replacement. Suggest a change to 60 months, or "prorated" (The implementation period will be different based on the number of protection units that have been identified for replacement).	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
This does not allow for time needed to make any changes based on the new revision. Altering the calculations and re-reviewing current changes that have been made in accordance with PRC-025-1 will take time. Any non-compliant relays found due to the new revision may	

Question 7	
cause a delay in our ability to comply. We would request that more time be given to allow for proper implemenation of this new revision.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Depending on the date that version 2 would eventually be approved, it is possible that that the version 2 enforcement date, for those assets explicitly in scope under version 1, could actually be earlier than the existing version 1 enforcement date. AEP recommends that the version 2 enforcement date should have the exact same enforcement date as in version 1 for those assets already explicitly in scope under version 1. As an example, the table below shows what would happen if the effective date for version 2 of PRC-025 were to be June 1 of 2018. As shown in the table provided, the version two enforcement dates for assets already explicitly in scope under version one, both for assets where no removal or replacement is necessary *and* for assets requiring removal or replacement, would be sooner that their corresponding enforecement dates under version one.

Requirement	Effective Date	Enforcement Date
PRC-025-1 R1 (No removal or replacement necessary)		

Question 7	
10/01/14 10/01/19 PRC-025-**2** R1 Assets Already Explictly in Scope (No removal or replacement necessary) 06/01/18 06/01/19 PRC-025-1 R1 (Requires removal or replacement) 10/01/14 10/01/21 PRC-025-**2** R1 Assets Already Explictly in Scope (Requires removal or replacement) 06/01/18 05/31/21 AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Donald Lock - Talen Generation, LLC - 5	
Answer	No

Question 7	
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No

Question 7	
Document Name	
Comment	
As currently written, it appears the implementation plan can actually shorten the current timeframes to become compliant with PRC-025. If PRC-025-2 was approved and became effective prior to 10/1/18, entities would have less time to comply with the 2 scenarios under "Load-responsive protective relays subject to the standard" in the implementation plans. Currently entities have until 10/1/19 to comply when they will be making a setting change to meet the setting criteria and 10/1/21 to comply when they will be removing/replacing the relay to meet the setting criteria. Tri-State recommends adding language similar to the commonly used "shall become effective on the later of XXXX or the first day of the XX calendar quarter". That would prevent entities from losing time they might have already planned on having to become complaint with PRC-025-1. Additionally, can the SDT explain why they changed the timeframes (from 60 and 84 months to 12 and 36 months respectively) under "Load-responsive protective relays subject to the standard" but not the ones under "Load-responsive protective relays which become applicable to the standard" provided in the implementation plans.	
Likes 1	PSEG - PSEG Fossil LLC, 5, Kucey Tim
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Implementation Period should align with the existing Implementation Period of PRC-025-1 because that is what utilities have been working toward.	

Question 7	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
The Implementation Plan should not require taking a special outage for PRC-025, and should therefore allow at least five years to make relay settings changes, and seven years to install new devices.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA does not agree that a 12-month implementation period is sufficient for changes to relay settings that now may be required due to the new applicability of the 50 (instantaneous overcurrent) element in PRC-025-2 Draft 1. The original PRC-025-1 implementation plan allowed 5 years from approval to implement settings changes. This 5-year period was sufficient for implementing new relay settings,	

Question 7	
even for nuclear units which are tied to refueling outage schedules. TVA has seven nuclear units. Some other entities have even more. It is unreasonable to expect nuclear units to schedule additional outages that could be required within the proposed 1-year implementation period, just to perform relay settings changes.	
Likes 2	PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No

Question 7	
Document Name	
Comment	
The current standard's implementation plan states that the entity must be compliant by October 2019, or by October 2021 for the removal or replacement of applicable relays. The proposed implementation plan only identifies the retirement of the previous standard and does not provide a transition period between revisions. We propose incorporating a clause that begins the compliance period no earlier than October 2019, and no earlier than October 2021 for the removal or replacement of applicable relays.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Unless the SDT clarifies that the PRC-025 applicability section refers only to PRC-025 relays on 1) substation Bulk Electric System (BES) elements and 2) individual power producing resource relays at the BES generators, and that all collector system protective relays are excluded, the first implementation of PRC-025-1 was not clear and entities will need 60 months to staff and build systems to support zero-defect compliance monitoring and change management.	
Likes 0	
Dislikes 0	
Response	

Question 7	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.	
Likes 0	

Question 7	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG recommends changing the implementation plan since there is no correlation between the number of the relays requiring replacement and the arbitrary implementation period. We suggest the implementation period to be a function of the number of relays involved. Alternate graded approach is also possible i.e. 25, 50, 75 & 100% corresponding to 5 years.	
Likes 0	
Dislikes 0	
Response	

Question 7	
Thank you for your comment. The drafting team does not want to mandate the approach to the implementation. The Implementation Plan allows a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	

Question 7	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 7	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	

Question 7	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Question 7	
Answer	
Document Name	
Comment	
The proposed Implementation Plan is consistent with the timelines for compliance with PRC-025-1. Texas RE suggests the SDT clarifies that entities making a determination that replacement or removal is necessary, triggering the 36-month compliance window, should document those conclusions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team sees that as administrative and the responsibility of the entity to be able to demonstrate its compliance with the standard.	

Question 8	
8. *Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.*	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Stating that this is a severe VSL and high VRF is way more severe than the actual risk for not being in compliance with PRC-025-2 especially for asynchronous generators. If the settings and studies are done correctly there is no risk of false tripping even if the pickups are not as high as the requirements in this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The VRF of High is consistent with the application of settings on load-responsive protective relays in PRC-023 – Transmission Relay Loadability and was approved by industry and regulatory authorities. Not setting load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment is a risk to reliability. The single Severe VSL is due to the requirement being binary (i.e., pass/fail). The NERC guidelines for writing VSLs require the greatest category of VSL to be used for binary conditions.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 8	
Reclamation recommends there is a need for high/moderate/low VSLs based on the number of relays impacted by the standard. Reclamation recommends a VSL similar to that for PRC-005-6 R3 and R4. Reclamation recommends the following VSLs: Requirement Number - R1 Lower VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on fewer than 5% of its load-responsive protective relays. Moderate VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 5% to less than 10% of its load-responsive protective relays. High VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 10% to less than 15% of its load-responsive protective relays. Severe VSL - The entity failed to apply settings in accordance with PRC-025-2 Attachment 1: Relay Settings, on 15% or more of its load-responsive protective relays.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the drafting team understands the approach, the performance of Requirement R1 is to set each load-responsive protective relay according to Table 1; therefore, the VSL does not lend itself to a gradated VSL.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe a performance-based criteria could be established for the Violation Severity Levels for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of Components the applicable	

Question 8	
entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. We recommend using the same criteria for this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. While the drafting team understands the approach, the performance of Requirement R1 is to set each load-responsive protective relay according to Table 1; therefore, the VSL does not lend itself to a gradated VSL.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes

Question 8	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes

Question 8	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 8	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	

Question 8	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 8	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Question 8	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 8	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 8	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	

Question 8	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 8	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Question 8	
Document Name	
Comment	
Texas RE recommends changing the “and” to an “or”. Additionally, Texas RE requests the SDT consider providing a justification of the “Long Term Planning” time horizon as it has a significant impact on Penalty calculations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting used the term “including” to eliminate confusion over the use of “or” or “and.” The Time Horizon of “Long-term Planning” is consistent with the NERC Time Horizons[6] use.	

[6] http://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Question 9	
9. ***Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.***	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
These options, and other options, which use the phrase “gross MW reported to the Transmission Planner” needs clarity. That values are reported to the Transmission Planner annually. These values change somewhat, annually. Should Transmission Owners re-evalute that data and the settings derived from that data annually? I believe the spirit of PRC-025 is met with a one-time implmenetation based on this generator data. There should be no burden on Transmission Owners to re-evaluate this geneator data every year and re-calculate setitngs every year. Even if the Transmission Owner chooses to calculate settings on data more conservative than what is reported to the Transmission Planner, there should not be a requirement against annually chaning data.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the MW value reported to the Transmission Planner is a minimum value for calculating the settings. Attachment 1 states the following “[i]f different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.” It is incumbent on the applicable entity to ensure compliance with the standard when reported values change.	
Donald Lock - Talen Generation, LLC - 5	

Question 9	
Answer	No
Document Name	
Comment	
Entities that took NERC at their word in performing calculations and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for the calculations under 14a, 15a, and 16a have not substantively changed as the voltage used in the calculation is the line nominal voltage. In the case of calculations under 14b, 15b, and 16b using simulation, the depressed voltage location was moved from the high-side of the generator step-up (GSU) transformer to the remote end of the line (i.e., at the transmission network) to account for the impedance of the generator lead line. Depending on line length and impedance, the simulation results would result in calculating an overly conservative setting had the simulation be performed from the remote end of the line. The drafting team believes "grandfathering" is not necessary as the simulation option use would not have been widespread. Also, through outreach of the drafting team, the revisions made will be providing entities setting alternatives where compliance was not previously feasible. Therefore, it is not expected that entities would have a need to perform new calculations due to the changes proposed in the standard.	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	
See comments and alternative approaches to meet the intent of the Standard in response to Question 2 above.	
Likes 0	

Question 9	
Dislikes 0	
Response	
Thank you for your comment. Please see the response in Question 2 above for Exelon.	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Entities that performed calculations per NERC guidance and (where necessary) making changes under PRC-025-1 should be "grandfathered" for PRC-025-2.r	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The process for the calculations under 14a, 15a, and 16a have not substantively changed as the voltage used in the calculation is the line nominal voltage. In the case of calculations under 14b, 15b, and 16b using simulation, the depressed voltage location was moved from the high-side of the generator step-up (GSU) transformer to the remote end of the line (i.e., at the transmission network) to account for the impedance of the generator lead line. Depending on line length and impedance, the simulation results would result in calculating an overly conservative setting had the simulation be performed from the remote end of the line. The drafting team believes “grandfathering” is not necessary as the simulation option use would not have been widespread. Also, through outreach of the drafting team, the revisions made will be providing entities setting alternatives where compliance was not previously feasible. Therefore, it is not expected that entities would have a need to perform new calculations due to the changes proposed in the standard.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	

Question 9	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[7] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

[7] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
We believe the standard is too inclusive of all load-responsive protective relays. The applicability of this standard should be reflective of other PRC Standards, such as NERC Reliability Standard PRC-019-2, and based on the BES definition and gross nameplate ratings of generation Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Each Generator Owner, Transmission Owner, and Distribution Provider is required to apply settings on each load-responsive protective relay while maintaining reliable fault protection. Similarly, PRC-019 (*Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection*) requires entities to verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. This is to ensure voltage regulating system controls, (including in-service limiters and protection functions) avoid disconnecting the generator unnecessarily, and that applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Question 9	
Cost efficiency would be achieved by focusing on the correct impactful objectives, such as common-mode design issues, while excluding zero-defect compliance monitoring/change management for individual collector systems or individual dispersed power producing resources. For example, without an outside source to provide internal capability curves, Option 5 may be extremely labor intensive to develop and maintain to zero-defect. Zero-defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. Reclamation recommends the SDT modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. This appropriately focuses compliance efforts on the measurable impacts of common-mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[8] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No

[8] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
Document Name	
Comment	
Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources. The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[9] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

[9] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 9	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 9	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Question 9	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 9	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Question 9	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	

Question 9	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 9	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	

Question 9	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Question 9	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes

Question 9	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	

Question 9	
Likes 0	
Dislikes 0	
Response	

Question 10	
10. ***Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict here.***	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so c may inform the drafting team of any such conflicts.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends that the SDT check to see if the inclusion of collector systems could infringe on state jurisdictions.	
Likes 0	

Question 10	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so they may inform the drafting team of any such conflicts.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is unaware of any state jurisdictional conflicts with the standard. The goal of the question is to reveal such conflicts through the applicable entities that have a working knowledge of the various regulatory functions, rules, orders, tariffs, rate schedules, legislative requirements, and agreements in their jurisdiction so they may inform the drafting team of any such conflicts.	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	No
Document Name	
Comment	

Question 10	
No from a technical point of view, but there might be some regional variances with the version approved by the Regie de l'Énergie du Québec.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team is not aware of any conflicts with Régie de l'énergie - Gouvernement du Québec.	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 10	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	

Question 10	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	

Question 10	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

Question 10	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 10	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

Question 10	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	

Question 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	

Question 10	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No

Question 10	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Fischette - Michael Fischette - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 10	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
11. ***Are you aware of a need for a regional variance or business practice that should be considered with this project? If yes, please identify the need here.***	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE requests this question be included for each project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The NERC developer for the project has forwarded the request to NERC Standards staff for consideration.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Question 11	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance	
Answer	No
Document Name	
Comment	
Likes 0	

Question 11	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No

Question 11	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Question 11	
Response	
Eleanor Ewry - Puget Sound Energy, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	

Question 11	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Con-Edison	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 3, 5, 1, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	

Question 11	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Question 11	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Normande Bouffard - Hydro-Québec Production - 5	
Answer	Yes
Document Name	
Comment	

Question 11	
Hydro-Québec TransÉnergie has proposed calculations and simulations for a particular configuration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team considered the approach presented to NPCC August 2016 and concluded that simulation was a more appropriate method for determining the generator response for a unit that is significantly reduced due to the impedance of the transmission line.	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
It would be beneficial for maintenance requirement to align with PRC-005 maintenance requirement since time between scheduled outages for generation units can be as long as 36 months.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	

Question 12	
12. ***If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:***	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	
Document Name	
Comment	
I was not able to log my vote in SBS despite being in the ballot pool and attempting to vote affirmative before the ballot close time. Please contact me to ensure this issue is remedied.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. NERC staff responded outside of the drafting team meeting.	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	
Applicability Section 4.1 references "3.2, Facilities." This appears to be a typographical error; consider correcting to reference "4.2 Facilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The numbering sequence has been corrected.	

Question 12	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
All settings should be based off load ability and equipment ratings like option 5b allows. Setting elements to arbitrary values called out in PRC-025 is not good sound engineering and poor practice for protecting electrical equipment. Settings should be based on IEEE standards and studies preformed by the professional licensed engineer developing the settings.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[10] The approach to determining the settings for load-responsive protective relays based on studies demonstrating that generator output and nameplate gross MW value provided a method for determining setting criteria. This was vetted and approved by industry in version one.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	

[1010] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

Question 12

Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.

For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 "protective elements" or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three "protective elements" or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more "protective elements" or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the "smart crowbar" example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.
5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.
6.

Question 12

In this 3,000 wind turbine example there are 21,300 "protective elements" to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn't include the substation System Protection devices that we already consider at the substation.

What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues?

Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solution:

1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

Replace the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

With:

3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

Question 12	
3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above. 4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item): **NERC Defined Element:** Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **NERC Defined Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[11] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions:	

[11] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12
1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., "20 - 30 MVA and typically has 10 – 15 turbines per single radial"). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term "protective element" is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." 3. There is no need to define "Collector System" within the standard. The standard uses the currently defined term "Element" to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms "Element" and "Facility" need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company
Answer
Document Name
Comment
Figure examples should be added to show examples of "elements utilized in the aggregation of dispersed power producing resources" for clarity as the BES definition excludes these elements from the BES.
Likes 0
Dislikes 0
Response
The SDT provided a new Figure 4 to clarify elements utilized in the aggregation of dispersed power producing resources (e.g., collector system, feeders).
Richard Jackson - U.S. Bureau of Reclamation - 1

Question 12	
Answer	
Document Name	
Comment	

Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that a Unit Auxiliary Transformer does not include excitation supply power potential transformers.

Reclamation recommends the SDT clarify what benefit is derived from zero-defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues.

Reclamation recommends the SDT clarify the definition of Unit Auxiliary Transformer (UAT) in footnote 1 on page 3 of 112 of the standard to state that, “a Unit Auxiliary Transformer does not include excitation supply power potential transformers.”

For clarity, Reclamation recommends the SDT state the PRC-025 “protective elements” or devices (which can be more than relays) expected to be in scope. Reclamation recommends the SDT evaluate the impact of PRC-025 in terms of the number of PRC-025 devices, similar to the impact of PRC-005. All of these items (and potentially more, based on the recent NERC Lesson Learned, “Loss of Wind Turbines due to Transient Voltage Disturbances on the Bulk Transmission System”) would have to be tracked for zero defects, such as perfect settings and perfect knowledge of changes. This could result in an entity’s PRC-025 program being the same or greater size and workload as its PRC-005-6 program.

Following are some possible solutions to help focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

Proposed Solutions:

1. Reclamation recommends that the drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more and the loss of individual collectors or individual generators.

Reclamation recommends replacing the proposed Applicability section 3.2.5

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

Question 12
with: **3.2.5** Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event. **3.2.6** Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified in 3.2.5. 2. Reclamation recommends that the drafting team consider defining "protective element" as, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system." A protective element excludes fuses. 3. Reclamation recommends that the drafting team consider adding a NERC Glossary defined term of "Dispersed Power Producing Resource Collector System" such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above. 4. Reclamation recommends that the drafting team consider modifying the existing NERC Glossary definitions of "Element" and "Facility" to separate plant issues from individual generator issues as follows: **Element:** Any electrical device with terminals that may be connected to other electrical devices such as *an individual generator, an individual dispersed power producing resource*, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a *generating plant or aggregate dispersed power producing plant*, a shunt compensator, transformer, etc.)
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Question 12
The drafting team notes that the Applicability section for unit auxiliary transformer (UAT) clearly does not include the excitation transformer. Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[12] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions: 1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., “20 - 30 MVA and typically has 10 – 15 turbines per single radial”). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term “protective element” is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of “load-responsive protective relay.” 3. There is no need to define “Collector System” within the standard. The standard uses the currently defined term “Element” to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms “Element” and “Facility” need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators
Answer

[12] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
Document Name	
Comment	
1. Section 4.1 identifies functional entities that are applicable to this standard. These entities apply load-responsive protective relays at the terminal ends of the Elements identified in Section 3.2, Facilities. However, we believe the applicability of these Facilities are listed under Section 4.2. We observe this inconsistency throughout the standard. 2. This project continues to run independent of the current implementation plan identified for NERC Reliability Standard PRC-024-1. Although the phased-in implementation of this standard is still on-going, it very probable that a registered entity has already developed a complete compliance program that addresses the current version of this standard. We simply ask the SDT to acknowledge this possibility. 3. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The drafting team corrected the section numbering error. 2. The drafting team acknowledges that entities may have taken any number of approaches to become compliant with the standard. The Implementation Plan allows a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	Project 2016-04 PRC-025-2Final.docx
Comment	
Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.	

Question 12

For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 "protective elements" or devices (which can be more than relays) expected by the PRC-025 drafting team.

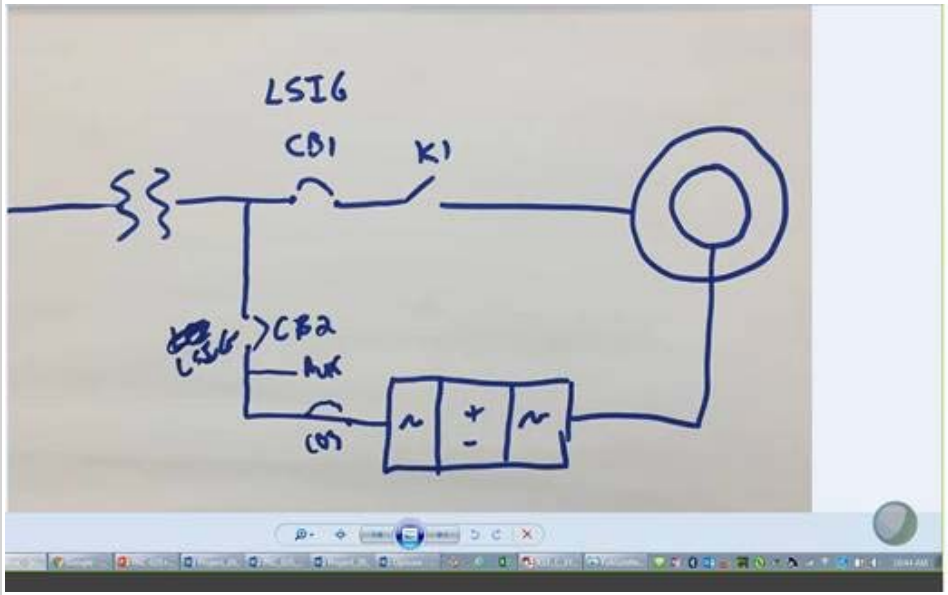
As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three "protective elements" or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more "protective elements" or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the "smart crowbar" example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.
5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.

In this 3,000 wind turbine example there are 21,300 "protective elements" to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn't include the substation System Protection devices that we already consider at the substation.

Question 12
What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements. **Proposed Solution:** 1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators. Replace the proposed Applicability section 3.2.5 *3.2.5 Elements utilized in the aggregation of dispersed power producing resources* With: **3.2.5** Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event. **3.2.6** Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5. 2. Request that the PRC-025 standards drafting team consider defining “Protective element” for PRC-025 means, “protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses. 3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as: **Collector System:** Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

Question 12	
4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of “Element” and “Facility” to separate plant issues from individual generator issues (thanks to Darnez for this item): **NERC Defined Element:** Any electrical device with terminals that may be connected to other electrical devices such as a generator, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components. **NERC Defined Facility:** A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.) Please see attached document for diagram.	
	
Likes 0	
Dislikes 0	
Response	

Question 12	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[13] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Response to Proposed Solutions: 1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., "20 - 30 MVA and typically has 10 – 15 turbines per single radial"). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient. 2. The term "protective element" is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay." 3. There is no need to define "Collector System" within the standard. The standard uses the currently defined term "Element" to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements. 4. The drafting team does not agree that the definitions of the terms "Element" and "Facility" need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	
Document Name	

[13] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
Comment	
Several times the term “Real Power output” is defined in the proposed standard as “100% of the aggregate generation gross MW capability reported to the Transmission Planner.” TVA believes that it can be difficult to determine what is meant by “capability reported to the transmission planner,” and would like to see the standard clarify on which reporting mechanism or process this generation capability is normally expected to be based. A Transmission Planner can have multiple capabilities reported for one unit. For example, a MOD-025 capability verified by test or operational data, versus a planned capability that reflects a modification to be implemented in the near future.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The “gross MW capability reported to the Transmission Planner” is based upon NERC Reliability Standard MOD-025-2. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	
Document Name	
Comment	
Table 1 seems to explicity require specific reach settings and does not address how to comply with the standard if using a quad element and not a mho element, even though a quad element is uncommon in generator relays. Additionally, there is not a clear path in the standard regarding load encroachment blocking. Load encroachment blocking is mentioned in the PRC-025-1 Application Guideline and the the NERC SPCS report “Considerations for Power Plant and Transmission System Protection Coordination” but is absent in the standard.	
Likes 0	

Question 12	
Dislikes 0	
Response	
Thank you for your comment. The drafting team notes that the standard addresses what is required and not how to accomplish the setting criteria. Requirement R1 requires that the entity apply settings on each load-responsive protective relay while maintaining reliable fault protection; therefore, an entity might have to employ alternative protection schemes to achieve the loadability requirements and reliable fault protection.	
Marc Donaldson - Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
In Table 1, Relay Type column, for Options 14, 15, 16, 17, 18, and 19, consider changing "…installed on the high-side of the GSU transformer and [on the] remote end of the line" to something like "…installed on the high-side of the GSU transformer and/or [on the] remote end of the line" or "…installed on the high-side of the GSU transformer, including [on the] remote end of the line." A simple 'and' suggests that relaying at both locations may be required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team clarified the relay location by moving the information from the "Relay Type" column of Table 1 to the "Application" column for each of the applicable Options.	
Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3	
Answer	
Document Name	
Comment	

Question 12	
The SDT should modify the applicability section to concentrate on common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded as in PRC-005-6. This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.	
Likes 1	OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
Dislikes 0	
Response	
Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[14] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE inquires about the use of the Application Guideline as there are several changes in the works with regards to attached documents. Texas RE's understanding is that any guidance as to how to comply with a standard will go through the Implementation Guidance	

[14] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Question 12	
process. Any technical basis will be in a Technical Rationale document. How does the Application Guidance in PRC-025-2 fit in with the new schematic? In addition, Texas RE requests the technical reason that the GO might provide a base setting on capability that is higher than what is reported to the Transmission planner, as noted in Attachment 1. Texas RE also noticed the following grammatical issues/typos: • The header still has "-1" throughout Standard. • Applicability section 4.1 references "3.2, Facilities" which does not exist. It should reference "4.2, Facilities". • Facility section 4.2.4 has two sentences that conflict. The first sentence says "used exclusively to export"; the second sentence says "may also supply". If an element is used exclusively for something, that precludes it from also including something else. • The Compliance Monitoring Process section is incorrectly numbered as "8" (and subparts 8.1, 8.2, etc.).	
Likes 0	
Dislikes 0	
Response	
GTB – Check with NERC staff The drafting team notes that the MW value reported to the Transmission Planner is a minimum value for calculating the settings. Attachment 1 states the following "[i]f different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner." It is incumbent on the applicable entity to ensure compliance with the standard when reported values change. Thank you for your comments. • The header has been corrected. • The Applicability section numbering has been corrected. • The Applicability has been revised to add obviously missing words and improving clarity.	

Question 12	
• The Compliance section numbering has been corrected.	
Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
None. Thank You	
Likes 0	
Dislikes 0	
Response	
George Brown - Acciona Energy North America - 5	
Answer	
Document Name	
Comment	
As written, NERC Reliability Standard PRC-025-2 Generator Relay Loadability does not account for equipment limitations of the generator step-up transformer or generation lead line that would not allow an entity to set it's protective relays to the level as specified within the standard. The SDT needs add additional option for these application that is similar to option 5B.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Equipment limitations for other applications in Table 1 have not been identified by industry.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	

Question 12	
Answer	
Document Name	
Comment	
Tri-State would like to point out that there seems to be an error in "Section 4.1 Functional Entities" where the sub bullets are referencing section "3.2, Facilities." That should be "4.2, Facilities."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The number error has been corrected.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG recommend that instead of “relay location” to use “relay associated instrument transformers (PT’s/CT’s) location”. Clarification are recommended for the cases where the protective device settings are not achievable due to additional possible constrictions related to the supply path associated equipment. This can be achieved by defining the “resource” in Option 5b.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard specifies the location of the relays based on the zone of protection of the Element. Option 5b allows closer matching of the resource output and should address the overloading concerns of the low voltage feeder facilities and other associated equipment in the path.	

Question 12	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	
Document Name	
Comment	
Please clarify if switch-onto-fault is meant to be included in Attachment 1: Relay Settings. Exclusion #1 states, “Any relay elements that are in service only during start up.” Is switch-onto-fault included as an element that is only service during start up? PRC-023 specifically addresses switch-onto-fault in Attachment A as applicable to the standard; addressing switch-on-to-fault in PRC-025 would provide consistency and clarity between the two similar standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Switch-on-to-fault (SOTF) schemes are not included because they are only enabled for a brief period following the re-energizing of a line.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	
Document Name	
Comment	
Section 4.1 (Functional Entities) references the Elements listed in Section 3.2 (Facilities); however, Section 3.2 (Facilities) does not exist within the PRC-025-2 – Generator Relay Loadability proposed standard document. Section 4.1 (Functional Entities) should instead be updated to reference the Elements listed in Section 4.2 (Facilities).	
Likes 0	
Dislikes 0	

Question 12	
Response	
Thank you for your comment. The error has been corrected.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy recommends the drafting team consider adding another option (perhaps 13c) that would address the high side UAT overcurrent settings under this standard. We suggest adding: *"Where there is only one UAT low side protective device that is set at a minimum 135% of the UAT nameplate or 135% or greater than load operating at .85 per unit voltage, the UAT high side protective device must be set equal to or coordinate with the low side protective device."* The issue this would address is the prudent protection settings and compliance of the high side overcurrent with the standard. In some instances, the high side overcurrent is coordinating with the low side overcurrent. Currently, there is nothing that is addressing the low side. We feel that this is a technical flaw in the standard, which should be addressed.	

Question 12	
Also, there are some instances where some BES UAT's with high side fuses will operate at less that 150% UAT ratings. Based on these instances, we feel that fuses should be considered as an addition to the relay type category. We suggest that the drafting team consider making the changes referenced above to correct the technical errors, or remove references to the UAT in the standard altogether.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of the drafting team's work is to revise PRC-025-1 as described in the Standards Authorization Request (SAR).[15] The drafting team is not authorized to make changes to the unit auxiliary transformer settings. Correct, the low-side protection was not addressed in the version 1 standard. This issue was studied by the version one drafting team following the approval of version 1. It was found that the individual plant feeder loadability was not a reliability issue. The NERC System Protection and Control Subcommittee addressed low-side UAT protection in the document called "Unit Auxiliary Transformer Overcurrent Relay Loadability During a Transmission Depressed Voltage Condition, March 2016."[16] Fuses are not subject to the standard. Only load-responsive protective relays.	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	

[15] http://www.nerc.com/pa/Stand/Project%20201604%20Modifications%20to%20PRC0251%20DL/Project_2016_04_SAR_2017_03_20_Clean.pdf

[16] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/NERC%20-%20SPCS%20UAT%20-%20FEB_2016_final.pdf

Question 12	
Section 4.2.5 should have a minimum threshhold. Section 4.1 should reference 4.2 not 3.2	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Applicability 4.2.5 already has a threshold based on the resource meeting the I4 inclusion of the Bulk Electric System (BES) definition as defined by the Glossary of Terms Used in NERC Reliability Standards. The incorrect applicability references and numbering have been corrected.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP has chosen to vote negative on the proposed draft of PRC-025-2, driven by our concerns related to the proposed implementation plan (detailed in our response to Q7). AEP recommends a more appropriate per unit voltage level of 0.85 per unit, rather than 1.0 per unit, for options 13a, 13b, 17, and 18 within Table 1. In the Applicability section, all references to “3.2, Facilities” should instead be “**4**.2, Facilities.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response concerning the Implementation Plan in Question 7.	

Question 12
The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin. Options 17 and 18 are associated with asynchronous resources and use 1.0 per unit voltage because the current is limited based on the rating of the resource regardless of a lower voltage. The Applicability number error has been corrected.

Additional comments/information received from Russel Mountjoy – MRO NSRF

Questions

1. Do you agree that the proposed new Option 5b in PRC-025-2, Table 1 addresses cases where the applicable entity is unable to achieve the 130% threshold of Option 5a for overcurrent relays? See Figure A also. If not, please explain why and provide an alternative proposal.

   ☐ Yes

   ☒ No

   Comments: Option 5b is helpful and a clear improvement. However, Option 5b isn't a complete solution. Not all solar and wind facilities are new. Some wind / solare facilities won't have an outside source that remains in business to provide internal capability curves. Therefore, Option 5 should allow a simulation option where entities can show through a verified model (MOD-026 / MOD-027) that the wind / solar farm will remain on-line for widespread voltage depressions which drives the 130% overcurrent margin reliability requirement.

   Response:

   Thank you for your comment. Option 5b is not intended to address the capability/response of aggregate resources as reflected in MOD-026 and MOD-027. However, Option 5b does not limit the entity's approach to determine the unit capability. Simulation options are specifically provided for synchronous machines due to the potential differences in their field-forcing response.

2. Do you agree that the proposed revisions to PRC-025-2 – Attachment 1: Relay Settings (including Table 1) for applications involving overcurrent relays clarify that the IEEE device element 50 (i.e., instanteous) as well as low voltage trip designations commonly

referred to as L (long time delay), S (short time delay), and I (instantaneous) by manufacturers are required to comply with the standard? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments: The NERC standard refers to relays and the Table 1 heading refers to relays, but Pickup was struck and Option 5 refers to overcurrent elements. Where the standard refers to "elements" please add the word "PRC-025 relay" in front to clearly state that only "PRC-025 relays" are applicable, not control systems, not protective algorithms, and not fuses.

If the drafting team meant to include more protective elements than relays, the NERC standard needs to clearly state the protective elements covered. NERC standards are written to zero defect and subject matter experts must clearly understand where the law applies. Until NERC standards allow some room for some small amount of error to be corrected without incurring a violation such as the six sigma or cyber security standards, NERC compliance standards and boundaries must be absolutely clear.

Response:

Thank you for your comment. The drafting team had already revised locations regarding "element" and "relay" to eliminate confusion. The drafting team does not agree that making the suggested revision adds clarity over the facilities that are specified in the Applicability section of the standard.

The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."

3. Do you agree that the proposed revisions in the "Application" column of Table 1 for Options 1 through 6 clarify that applicable protective relays associated with "all" listed Elements are to be set using the setting criteria of Table 1? If not, please explain why and provide an alternative proposal.

☐ Yes

☒ No

Comments: No. There is a discussion in the Technical Guidance section that discusses the inclusion of collector system protective elements. However, Table 1 uses the NERC capitalized term "Element" which specifically excludes collector systems via NERC and

industry agreement in 2014. This is documented in the NERC bulk Electric System Definition Reference Document dated April 2014, see the cover page and page 21 of 85.

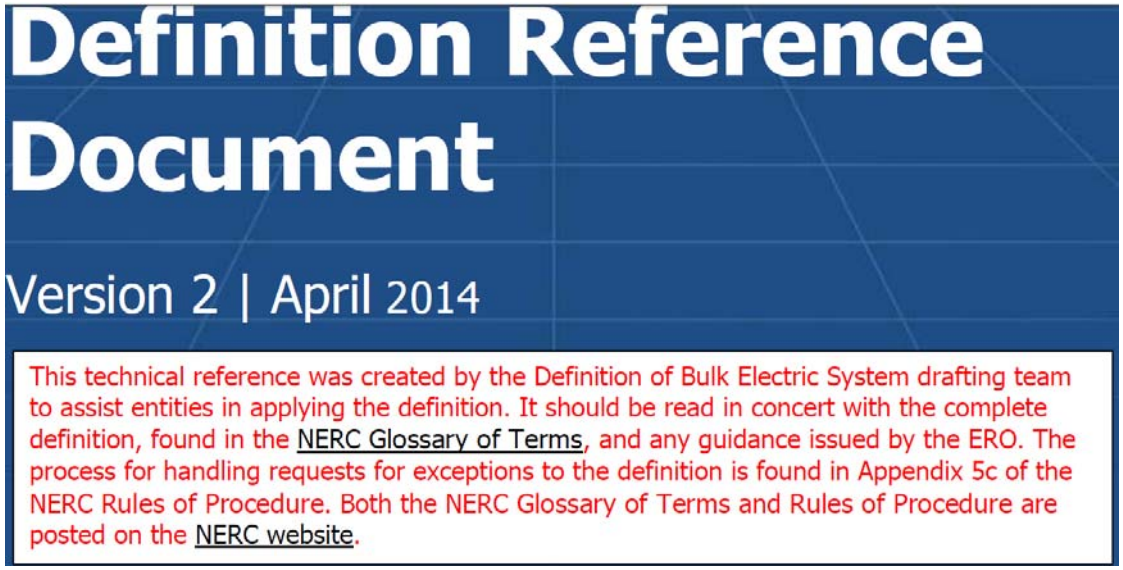
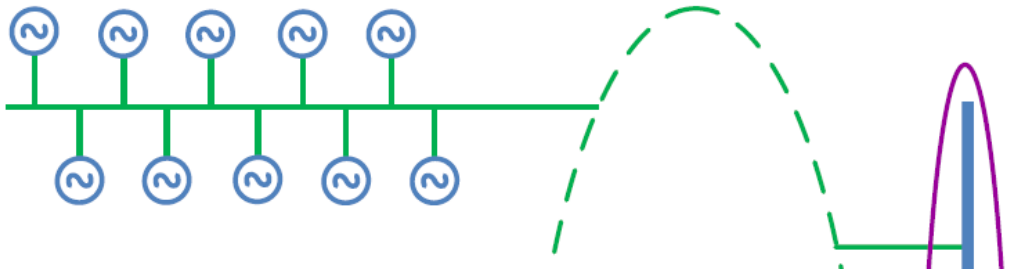


Figure I4-2 depicts a dispersed generation site and substation design with unknown collector system configuration.

Typical dispersed generation site and substation design (single transformation of voltage level) with a gross aggregate nameplate rating of 80 MVA (Individual Generator Unit Rating: 2 MVA). By application of Inclusion I4 the dispersed power producing resources and the Elements from the point of aggregation to the common point connection are BES Elements.

Green indicates the portions of the Collector System that are not included in the BES.

Blue identifies the dispersed power producing resources and BES Elements between the point where those resources aggregate to greater than 75 MVA to a common point of connection at a voltage of 100 kV or above.



Link:

http://www.nerc.com/pa/RAPA/BES%20DL/bes_phase2_reference_document_20140325_final_clean.pdf

Please state that Technical Guidance is for examples only, guidance isn't enforceable and cannot alter the scope of compliance.

Response:

Thank you for your comment. The NERC Bulk Electric System Definition Reference Document dated April 2014 is used for the determination of Bulk Electric System (BES) Elements and the "collector system configuration" is not relevant to the determination of whether a BES Resource meets the definition. However, the PRC-025 Reliability Standard applicability is based on generation resources that meet the criteria under Inclusion I4. Once a resource is applicable, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan, the Elements listed in 4.2.1 through 4.2.5 become applicable regardless of the BES definition (4.2.5. Elements utilized in the aggregation of dispersed power producing resources). The definition of "Element" (Any electrical device with terminals that may be connected to other electrical

devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.) as used in the Applicability of PRC-025 meets this definition.

4. Do you agree that the proposed revisions in Table 1 for Options 14 thorugh 16 address cases where generating facilities are remote to the transmission network by allowing setting criteria based on the simulation of field forcing in response to a 0.85 per unit voltage at the remote end of the line? If not, please explain why and provide an alternative proposal.

   ☒ Yes

   ☐ No

   Comments:

5. Do you agree with the removal of the leading term "Pickup" in "Pickup Setting Criteria" in Table 1? If not, please explain why and provide an alternative proposal.

   ☐ Yes

   ☒ No

   Comments:

   The applicability section states that PRC-025 applies to relays. Removing "Pickup" suggests the drating team is looking for additional protective elements in addition to relays. If the SDT plans to consider more than PRC-025 protective relays, the applicability criteria needs to be adjusted in addition to removing "Pickup". Relays or what is meant by relay for PRC-025 needs to be clearly defined so compliance can clearly identify when compliance has been met.

   Response:

   Thank you for your comment. The drafting team addressed the removal of "Pickup" from the standard as scoped in the SAR and agrees that "Settings Criteria" is a more appropriate term for the value. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1.

   The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."

6. Do you agree with the miscellaneous revisions made to the PRC-025-2 – Application Guidelines? If not, please explain why and provide an alternative proposal.

   ☒ Yes

   ☐ No

   Comments:

7. Do you agree with implementation period of (1) 12 months for cases with equipment removal or replacement **is not** necessary, and (2) 36 months where equipment removal or replacement **is** necessary based on the considerations listed in the Implementation Plan? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

   ☐ Yes

   ☒ No

   Comments: No. The SDT was not clear with its first implementation that collector systems were in scope as Technical Guidance cannot alter the scope of compliance and the applicability section 4.2.5 by itself did not make it clear that non-BES collector systems were being included contrary to the NERC Bulk Electric System Definition Reference Document dated April of 2014. Entities need another 60 months to staff and build systems of record supporting zero defect compliance monitoring and change management on non-BES collector systems.

   Response:

   Thank you for your comment. The drafting team has revised the Implementation Plan to allow a 60/84 month implementation for the Table 1 Options where the 50 element has been specifically added and an additional phased-in periods for other revised Table 1 Options.

   Do you agree with the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for the requirement in the proposed PRC-025-2? If not, please identify the need here.

   ☒ Yes

   ☐ No

   Comments:

8. Do the revisions proposed in PRC-025 provide a cost effective solution to the issues? For example, the revisions (i.e., Options 14b, 15b, and 16b) addressing remote weak generating plants in comparison to a strong transmission system and using the resource capability curve (i.e., Option 5b) to demonstrate loadability over the current 130 percent setting criteria? If not, please identify other cost effective alternatives of the issues addressed in the project.

☐ Yes

☒ No

Comments: Not as proposed. Cost efficiency can be achieved by focusing on the right impactful objectives. Focus on common-mode design issues and exclude zero defect compliance monitoring / change management for individual collector systems or individual dispersed power producing resources.

The NSRF suggests the SDT modify the applicability section to concentrate of common-mode design issues affecting 75 MVA or more of aggregated dispersed power resource generators. Zero defect compliance monitoring and change management for collector systems and individual generators should be clearly excluded similar to PRC-005-6.

This appropriately focuses compliance efforts on the measurable impacts of common mode design issues and reduces the administrative burden of explicitly tracking and monitoring individual dispersed power producing resources.

Response:

Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance17 have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

[17] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

9. Are you aware of any conflicts between the proposed standard revisions and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement? If **yes**, please identify the conflict here.

   ☐ Yes

   ☒ No

   Comments: No, but the SDT should check to see if the inclusion of collectors sytem(s) could infringe on state jurisdictions.

   Response:

   Thank you for your comment. The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

10. Are you aware of a need for a regional variance or business practice that should be considered with this project? If **yes**, please identify the need here.

    ☐ Yes

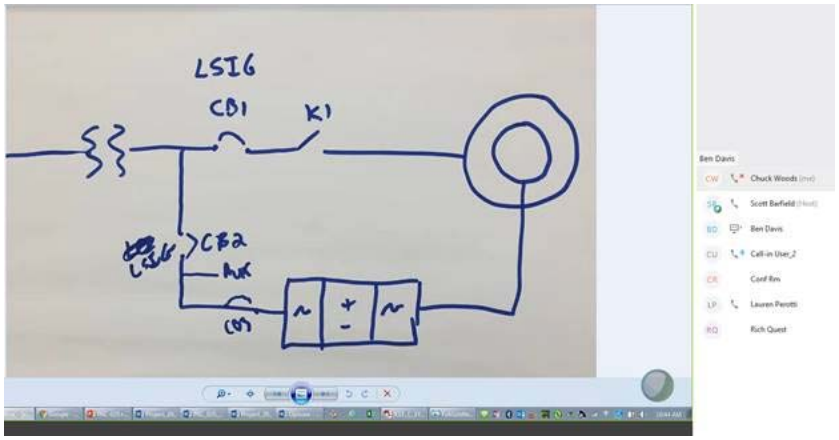
    ☒ No

    Comments:

11. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:

    Comments:

    Member entities, regulators, and regional entities need to have the same pictures and concepts so that potential staff and cost effectiveness discussions can be considered. Consider the following individual dispersed power producing resource picture discussed at the PRC-025 SDT.



For clarity, consider comparing impacts in terms of PRC-025 devices to PRC-005 devices. Discuss PRC-025 "protective elements" or devices (which can be more than relays) expected by the PRC-025 drafting team.

As an example, a GE wind turbine can have two nacelle breakers / relays and a molded case breaker /relay at the base of the wind tower, creating three "protective elements" or devices per wind turbine. Each wind turbine has a 690 / 34,500 volt padmount transformer with a low-side and high-side fuse potentially creating three more "protective elements" or devices per padmount if included in the PRC-025 protective element definition. Each radial collector can handle approximately 20 - 30 MVA and typically has 10 – 15 turbines per single radial collector breaker. All of these items (and potentially more, given the "smart crowbar" example from the recent NERC lessons learned) would have to be tracked for zero defects, such as perfect settings, coordinated, and perfect knowledge of changes.

Extrapolating the above example for approximately 3,000 wind turbines you could easily have a PRC-025 program that quickly surpasses the workload of a PRC-005-6 program:

1. Wind turbine protective elements (breakers CB1, CB2, and CB3 per turbine) = 3*3,000 turbines = 9,000 protective elements to track and coordinate.
2. Other wind turbine protective elements such as smart crowbars = 1 smart crowbar * 3,000 turbines = 3,000 protective elements to track and coordinate.
3. Each wind turbine has a padmount transformer that may need to be tracked and coordinated = 3,000 padmount transformers to track and coordinate.
4. Padmount protective elements such as fuses (one high-side and one low-side) if included in a future protective element definition = 2*3,000 padmount transformers = 6,000 protective elements to track and coordinate.

5. Radial collector breakers = 300 radial collector breakers assuming on average each collector breaker serves approximately 10 MVA of wind generation and coordinate.

   In this 3,000 wind turbine example there are 21,300 "protective elements" to track and maintain to zero defect for PRC-025. Exclude the padmount transformer fuses, and the number drops by 6,000 devices to 15,300. Excluding the padmount transformers and fuses drops the number to 12,300 devices to track and coordinate. This doesn't include the substation System Protection devices that we already consider at the substation.

   What benefit is derived from zero defect compliance monitoring and change management of individual PRC-025 protective elements versus addressing common mode design issues?

   Below are some possible comments on PRC-025 to focus on the important reliability impacts of common-mode design issues versus individual resources or protective elements.

   Proposed Solution:

   1. Request that the PRC-025 standards drafting team consider the following applicability section changes to differentiate between significant Bulk Electric System (BES) Impacts that risk the loss of 75 MVA or more versus the loss of individual collectors or individual generators.

      Replace the proposed Applicability section 3.2.5

      ~~*3.2.5 Elements utilized in the aggregation of dispersed power producing resources.*~~

      With:

      3.2.5 Dispersed Power Producing Resource collector system common design mode issues that risk the loss of 75 MVA or more for a single event.

      3.2.6 Protection elements used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above are excluded except for common design mode issues identified for 3.2.5.

2. Request that the PRC-025 standards drafting team consider defining "Protective element" for PRC-025 means, "protective tripping relays, protective tripping padmount relays, or protective generator control system trips designed to limit individual generator damage on the collector system. Protective element excludes fuses.

3. Request that the PRC-025 standards drafting team consider defining a NERC Dispersed Power Producing Resource Collector System such as:

Collector System: Radial facilities used to aggregate dispersed power producing resources designed primarily to deliver such aggregate capacity to a common point of connection at a voltage of 100 kV or above.

4. Request that the PRC-025 standards drafting team consider modifying the existing NERC definition of "Element" and "Facility" to separate plant issues from individual generator issues (thanks to Darnez for this item):

NERC Defined Element: Any electrical device with terminals that may be connected to other electrical devices such as ~~a generator~~, an individual generator, an individual dispersed power producing resource, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

NERC Defined Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a ~~generator~~ generating plant or aggregate dispersed power producing plant, a shunt compensator, transformer, etc.)

Response:

Thank you for your comment.

The drafting team understands dispersed generation resources (DGR) increases the administration of compliance for demonstrating that the resource meets the standard; however, entities through NERC Compliance Guidance[18] have a process to address compliance approaches with the standard. The first version of the standard addressed directives in FERC Order 733 to ensure load-responsive protective relays associated with generation Facilities are set at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

[18] http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Response to Proposed Solutions:

1. The suggested rewording of Section 3.2.5 (corrected to 4.2.5) and new Section 3.2.6 effectively eliminate load-responsive protective relays for Elements utilized in the aggregation of dispersed power producing resources as not many, if any, of these Elements would have an aggregate 75 MVA or greater as noted above (e.g., "20 - 30 MVA and typically has 10 – 15 turbines per single radial"). The goal of the standard is achieved when the these Elements are set not to trip based on a 1.0 per unit voltage to ensure the connected generation continues to produce Real Power and Reactive Power during a system transient.
2. The term "protective element" is not used in the standard. By virtue of the way PRC-025 is written in the Applicability, fuses are excluded. The Applicability is intended to list what is applicable, which is load-responsive protective relays at the terminals of Elements listed in the standard. The drafting team added a footnote to the Applicability section to clarify that low voltage protection devices that have adjustable settings are included within the context of "load-responsive protective relay."
3. There is no need to define "Collector System" within the standard. The standard uses the currently defined term "Element" to associate the Facilities for which the load-responsive protective relays are applied at the terminals of the Elements.
4. The drafting team does not agree that the definitions of the terms "Element" and "Facility" need to be modified to improve clarity within the standard. The standard addresses load-responsive protective relays at the terminals of those Elements listed under the Facilities section of the Applicability.

End of Report