Consideration of Comments

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation (PRC-025-1)

The Project 2010-13.2 Drafting Team thanks all commenters who submitted comments on the proposed standard, PRC-025-1 which was posted for a 30-day formal comment period from October 5, 2012 through November 5, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 39 sets of comments, including comments from approximately 112 different people from approximately 90 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Summary Consideration

In the previous initial posting and first formal comment period, the standard received valuable comments. The Generator Relay Loadability Standard Drafting Team ("drafting team") made significant improvements to the standard based on these comments. The drafting team believes it has addressed stakeholder comments and concerns in such a way that the standard is improved and meets the expectations expressed in comments for reliability and industry approval.

Majority comments revealed a number of common concerns which resulted in changes to the main body of the standard. Concerns and summary changes include: The word "install" in Requirement R1 is not an industry standard word – the word "install" was replaced with "apply" and Measure M1 was changed to comport with R1, the phrase "while maintaining reliable protection" was updated by inserting the word "fault" to make the phrase "while maintaining reliable fault protection," the Measure M1 was revised to remove the appearance of adding to the requirement by listing the evidences as examples, potential overlap with the current PRC-023-2 – Transmission Relay Loadability Reliability Standard is being addressed through a proposed revision outlined in the posted supplemental Standards Authorization Request (SAR), and a more understandable structure of Table 1 was created for clarity.

Majority comments revealed a number of common concerns which did not result in changes to the main body of the standard. Concerns and summary responses include: The concept of "identify, assess, and correct," was not implemented as it is not practical for this type standard, flexibility in setting relays is not needed because the standard already provides a number of multiple options (e.g., a simple calculation, a more complex and precise calculation, or the most precise method using simulation), and Measure M1 does not need to include a provision for entities that are already compliant because the implementation plan allows sufficient time for entities to document compliance.

Minority comments revealed a number of independent concerns which resulted in changes to the main body of the standard. Concerns and summary changes include: The standard does not pertain to protective functions for conditions such as inadvertent energization, or flashover schemes – exceptions have been included in Attachment 1: Relay Settings, applicable load-responsive protective relays based on connection or configuration was not clear – the standard now clarifies this by describing the appropriate terminals, confusion about using the seasonal output capability - resolved by removing the word “seasonal” to be consistent with the proposed MOD-025-2, and protective relay nomenclature (i.e., 51C and 51R) is not consistent with industry - updated to 51V-R and 51V-C for greater clarity and consistency.

Minority comments revealed a number of independent concerns which did not result in changes to the main body of the standard. Concerns and summary responses include: The standard does requires an entity to install load-responsive protective relays – the standard only applies to the those Facilities in the “Applicability” section, the out-of-step protective relays, exciter power potential transformers (PPT), and isolated phase bus (IPB) were not included in the applicability – to comport with the scope of the project they were not included in the applicability, PRC-025-1 may conflict with standards PRC-019 and MOD-024 – these standards relate to AVR protection and Real Power modeling (respectively), the standard appears to encourage Generator Owners to exceed the manufacturer’s rating of equipment – the standard does not represent an intentional operating point, standard did not include provisions for a light load condition (i.e., 40%) – this condition was considered and found not to have a reliability benefit in the standard, the standard should mirror PRC-023-2 – Transmission Relay Loadability – transmission loadability responds to a wide variety of topologies affect the loadability resulting in many different criteria and is not a practical fit for PRC-025-1, the standard requires entities to perform modifications to their protective relays or protection philosophies to achieve the required protection to satisfy this standard – the standard may require entities to address new technologies or philosophy changes to comply, and entities desired having an RSAW to compare for auditing – the drafting team provided input to NERC Compliance in the development of the PRC-025-1 RSAW and it may be viewed under the Compliance area of the NERC website.

Comments revealed a number of common concerns which resulted in changes to the Guidelines and Technical Basis. Concerns and summary changes include: The standard lacks clarity about the duration to which the standard applies to “adequately protect its equipment” for fault conditions – clarifying text was added, there is a lack of clarity about the duration to which the standard applies for overload conditions – clarifying text was added, the standard needs examples that illustrate the calculations needed to derive impedance and overcurrent values – extensive example calculations have been added for clarity.

Now that the standard has received formal industry input and standard drafting team modifications, the standard will advance to its second formal comment period which will include an initial ballot to be conducted in the last ten days of the comment period.

Purpose: The Purpose statement was revised to better reflect the intent of the standard based on industry comment.

Applicability: The Applicability section was revised to clarify the Facilities to which the standard is applicable. The drafting team made a clarifying change in section 3.1.1 to eliminate potential overlap with the standard, PRC-023-2.[1] The phrase “at the terminals of” was applied to the proposed PRC-023-3 standard in the Applicability section. Using this phrase demarcates the applicability by identifying the location of the load-responsive relay. To conform the draft 2 of PRC-025-1 with the proposed PRC-023-3 revision, the standard drafting team “3.2.4 Generator interconnection Facility(ies)” to the Applicability. This addresses conditions where generation Facility ownership may not be typical of the industry to comport with PRC-023-3 revision and to avoid a potential gap between the two standards.

Effective Date: No change. See the implementation plan for the proposed two-phased approach.

Requirement: The drafting team made a minor change to Requirement R1 to address several comments. The word “install” was replaced with “apply” to be more consistent with industry terminology and usage.

Measures: The Measure M1 was revised to comport with the revision to Requirement R1. This measure was further edited to remove the appearance that the measure was requiring additional performance over and above the performance of Requirement R1 by listing the evidence as examples.

Compliance Monitoring Process: Typographical correction.

Violation Severity Levels: The drafting team has provided a single VSL for Requirement R1, the only requirement in the standard. The posted Violation Risk Factors and Violation Severity Levels Justification document describe how the standard drafting team’s proposed VRFs and VSLs comply with the current guidelines for constructing VRFs and VSLs.

Attachment 1: Relay Settings: The drafting team made clarifying improvements to the introductory section of the attachment. Additional information was appended concerning no-load tap changers (NLTC) and on-load (OLTC) tap changers and relay elements that are excluded from the standard. Additionally, exclusions for certain application of load-responsive protective relay elements and the conditions to which the exclusions apply.

Table 1: Relay Loadability Evaluation Criteria: The drafting team made substantial improvements to Table 1 based on industry stakeholder comment. Table 1 has been restructured such that the first

[1] The drafting team has posted a supplemental Standard Authorization Request to make conforming revisions to PRC-023-2 – Transmission Relay Loadability to eliminate potential overlap between the proposed PRC-025-1 standard.

column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers (UAT), and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column now identifies each load-responsive protective relay (e.g., 21, 51, 51V-C, 51V-R, and 67) according to its application listed in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars may be blank or contain information text to bring awareness to the reader to information on a following page.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for a given application has one or more options (i.e., "ways") to determine the bus voltage and associated pickup setting criteria. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

Table 1 is further formatted by alternately shading groups of relays within a similar application to aid reader awareness. Also, intentional buffers were added to the table so that similar options would be paired together on a per page basis. These buffers may be blank or contain information text to bring awareness to the reader to information a following page. Note that some applications may have additional pairing that might occur on adjacent pages.

Guidelines and Technical Basis: Overall, this section was rewritten to parallel the new structure of Table 1 and has been separated into its own document for manageability. Comments revealed that conditions may exist where a Generator Owner might apply a phase directional time overcurrent relay (67) – directional toward the Transmission system. Given this possibility, the drafting team concluded this relay function should be included in the standard to eliminate a gap and avoid confusion with this type load-responsive protective relay.

The following is provided to illustrate the reorganization to Table 1.[2]

Application	Relay Type	Draft 1 Option	Draft 2 Option
Synchronous Generators	Phase distance relay (21) – directional toward the	1	1a

[2] The drafting team inserted the new Table 1 structure in the "redline to draft 1" in order to present the textual changes to the options and avoid the issues with demonstrating the redline changes of a table. Note that the redline to draft 1 may give the appearance, for some options, that the cross-reference of the options listed here may not be correct. This is due to the application's creation of the redline; therefore, use this table cross-reference to review how the options were revised.

Application	Relay Type	Draft 1 Option	Draft 2 Option
	Transmission system	2	1b
		3	1c
	Phase time overcurrent relay (51V-R) – voltage-restrained	5	2a
		6	2b
		7	2c
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	9	3
Asynchronous generators (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	4	4
	Phase time overcurrent relay (51V-R) – voltage-restrained	8	5
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	-	6
Generator step-up transformer – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	13	7a
		14	7b
		15	7c
	Phase time overcurrent relay (51)	-	8a
		10	8b
		11	8c
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	9a
		-	9b
		-	9c
Generator step-up transformer – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	16	10
	Phase time overcurrent relay (51)	12	11a
		-	11b
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	12
Unit auxiliary transformers (UAT)	Phase time overcurrent relay (51)	17	13a
		-	13b
Generator interconnection Facilities – synchronous generators	Phase distance relay (21) – directional toward the Transmission system	-	14a
		-	14b
	Phase time overcurrent relay (51)	-	15a
		-	15b
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	16a
		-	16b

Application	Relay Type	Draft 1 Option	Draft 2 Option
Generator interconnection Facilities – asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	-	17
	Phase time overcurrent relay (51)	-	18
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	-	19

Example calculations were also added to the Guidelines and Technical Basis as requested by a number of commenters.

Implementation Plan: The implementation plan was revised to provide additional information about the considerations made by the drafting team. More importantly, the drafting team revised the implementation plan to provide industry a two-phase approach to implementing the standard. As proposed, entities will have 48 months to apply settings and become 100%compliant on existing load-responsive protective relays or, where equipment requires replacement, 72 months (two additional years) to replace equipment with the required settings and become 100% compliant.

VRFs and VSLs: The drafting team developed and has provided the VRF and VSL justifications based on FERC and NERC guidelines for industry review.

Additional Information

All comments submitted may be reviewed in their original format on the standard's 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 Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[3]

Index to Questions, Comments, and Responses

[3] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Domionion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
25.	Christina Koncz	PSEG Power LLC	NPCC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Ron McIvor	OPPD	MRO	1, 3, 5
4.	Valerie Pinamonti	AEP	SPP	1, 3, 5
5.	Mahmood Safi	OPPD	MRO	1, 3, 5
6.	Joe Border	MsPhearson Board of public utilities	SPP	1, 3, 5
7.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	David Thorne	Pepco Holdings Inc. & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Llight	RFC	1
2.	Alvan Depew	Pepco Holdings	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2.	Clem Cassmeyer	Western Farmers Electric Cooperative	ERCOT	1, 5
3.	Tom Alban	Buckeye Power, Inc.	RFC	3, 4
4.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	SERC	1
5.	Susan Sosbe	Wabash Valley Power Association	RFC	3
6.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5

5.	Group	Kent Kujala	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Szulczewski		RFC	3, 4, 5

6.	Group	Will Smith	MRO NSRF	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD DAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM BREENE	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	5, 6, 1, 3
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	DAN INMAN	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	NPCC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	MRO	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Fran Halpin	Duty Scheduling	WECC	5
2.	Dean Bender	SPC Technical Svcs	WECC	1
3.	Stephen Enyeart	Customer Service Engineering	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Stephen	Berger	PPL Generation, LLC	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E and KU Services	SERC	3

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
	Company 3. Annette M. Bannon 4. Elizabeth A. Davis	 PPL Generation, LLC PPL EnergyPlus, LLC	 RFC 5 MRO 6										
12.	Individual	Emily Pennel	Southwest Power Pool Regional Entity										X
13.	Individual	Jim Watson	Dynegy, Inc.					X					
14.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
15.	Individual	ryan millard	pacificorp	X		X		X	X				
16.	Individual	Shammara Hasty	Southern Company (Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation Energy Market)	X		X		X	X				
17.	Individual	Ed Croft	Operational Compliance	X		X		X					
18.	Individual	DeWayne Scott	Tennessee Valley Authority	X		X		X	X				
19.	Individual	Jeffrey Streifling	ATCO Power										
20.	Individual	Thad Ness	American Electric Power	X		X		X	X				
21.	Individual	Michael Falvo	Independent Electricity System Operator		X								
22.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
23.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
24.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
25.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
26.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
27.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
28.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
29.	Individual	Timothy Brown	Idaho Power Company	X		X							
30.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
32.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
33.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
34.	Individual	Patrick Brown	Essential Power, LLC					X					
35.	Individual	Anthony Jablonski	ReliabiltiyFirst										X
36.	Individual	Kirit Shah	Ameren	X		X		X	X				
37.	Individual	Don Jones	Texas Reliability Entity										X
38.	Individual	Maggy Powell	Exelon Corporation and it’s affiliates	X		X	X	X	X				
39.	Individual	Patrick Brown	North American Generator Forum										

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Two entities submitted comments in support of those comments submitted by the North American Generator Forum (NAGF) industry trade association. One entity, Wisconsin Electric Power Company, provided additional comments for questions 1, 3, and 4; responses to these comments are found in their respective questions. Two additional entities (Essential Power, LLC and PPL and Affiliates) submitted the same or near same comments as the NAGF under the comment questions 1, 2, 3, 4, and 5 rather than affirming their support in this section.

Organization	Supporting Comments of "Entity Name"
Dynegy, Inc.	North American Generator Forum
Wisconsin Electric Power Company	NAGF (North American Generator Forum) In addition to these, we offer the following comments: **Response:** Other comments are found under the corresponding questions below.
Response: Thank you for your comments, please see the responses provided below for the NAGF industry trade association found in question #5.	

1. **Is the performance of Requirement R1 (and Measure M1) clear that the Generator Owner must determine and install settings on its load-responsive protective relays in accordance with PRC-025-1 – Attachment 1: Relay Settings? If not, provide specific suggestions to improve or clarify the performance.**

Summary Consideration:

Approximately 18 commenters representing about 61 entities provided comments for question #1. Fourteen common themes were revealed by commenters; of those, about half represent majority opinions by comment count and entities represented.

The first two majority comment themes did not result in any substantial change.

(1) Six comments supported by at least 12 entities were concerning an entity being able to "adequately" protect its equipment under the requirements anticipated by the standard. The drafting team responded that entities must still "adequately" protect their equipment with regard to faults; however, an entity may need to perform modifications to its protective relays or protection philosophies in order to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the standard provides suitable options to address the concern and the drafting team has developed the implementation plan to accommodate an entity that may need to perform modifications to its protective relays or protection system philosophies to achieve compliance with the standard and reliable fault protection.

(2) Three comments from at least nine entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as "field-forcing" which is a loadability issue, not an overload condition. This duration of which is within the thermal overload limits raised by the comments.

The next three majority comment themes resulted in changes to the standard.

(3) Four comments from at least six entities were concerned about the word "install" in Requirement R1. The drafting team addressed this concern by replacing "install" with "apply" to be more consistent with industry terminology.

(4) The drafting team received two comments supported by at least nine entities to consider developing a Reliability Standard Audit Worksheet (RSAW) document contemporaneously with the development of the standard. This idea was embraced and the drafting team provided NERC Compliance with valuable input into a draft RSAW for posting on the NERC website (www.nerc.com) under the Compliance tab. Entities following the development of PRC-025-1 may review the posted draft RSAW and provide feedback. Development of the RSAW is not a part of the standard development process and feedback should be provided through the RSAW feedback form to NERC Compliance.

(5) About three comments also supported by at least six entities were concerned about the phrase “while maintaining reliable protection” in Requirement R1. The drafting team addressed this concern through a minor change, by inserting the word “fault” to make the phrase “while maintaining reliable fault protection.” The standard is conveying that entities must install settings for loadability for the conditions found in Attachment 1 (e.g., depressed voltages) and must also provide the necessary (i.e., reliable) fault protection for equipment.

The next three comment themes did not result in changes to the standard.

(6) Two comments supported by at least nine entities were received which suggested restructuring the standard using the concept of “identify, assess, and correct” as utilized by some of the recent Critical Infrastructure Protection (CIP) version five standards. The drafting considered this approach; however, determined that it was not a good fit considering settings on generation facilities are not systematically revisited unless a major change occurs to the generation unit or associated equipment.

(7) Two comments also supported by at least nine entities requested greater flexibility in setting their load-responsive protective relays. The drafting team responded that the standard by the use of “Options” has provided this flexibility. To determine settings, an entity may select a simple calculation, a more complex and precise calculation, or the most precise method using simulation. Additionally, the standard provides each entity the ability to set its load-responsive protective relays more stringent than the values required by the Table 1 in Attachment 1.

(8) The last majority single comment supported by at least 17 entities expressed concern that no consideration in Measure M1 was given to entities that may already be compliant with the standard. The drafting team did not make any changes, but notes that the implementation provides an adequate duration for an entity to document their compliance for audit purposes.

The next two of six minority comment themes resulted in a change to the standard.

(9) One comment supported by at least two entities was concerned that the standard may also apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(10) One comment also supported by at least eight entities was concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

The last four minority comment themes did not result in a change to the standard.

(11) Two comments supported by at least two entities concerned the applicability of load-responsive protective relays requiring an entity to install relays. The drafting team clarified in the document that only those load-responsive protective relays as identified by the Applicability section of the standard are applicable and the standard and does not require entities to install such relays.

(12) One comment supported by at least eight entities was concerned about the potential overlap between the PRC-024-1 currently under development and the draft PRC-025-1 standard. The drafting team previously identified this issue and coordinated with the PRC-024-1 drafting team to have the load-responsive protective relay references removed from the PRC-024-1 footnote to provide greater distinction between the standards.

(13) One comment supported by at least two entities suggested that load-responsive protective relays protecting exciter power potential transformers (PPT) and isolated phase bus (IPB) or commonly referred to as ISO Phase Bus should be applicable to the standard. The drafting team did not include this equipment as it was outside the scope of the project's SAR.

(14) One comment provided by a single entity raised concern that PRC-025-1 maybe in conflict with standards PRC-019 and MOD-024. The drafting team reviewed these standards and determined that PRC-019 pertains to coordination of applicable protective functions regarding automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict. The standard MOD-024 addresses the reported output capability a Generator Owner would use in determining its settings under PRC-025-1 and also has no observed conflict.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1) As written R1 can be read to require the GO to use load-responsive protective relays. The wording of the first sentence in Attachment 1 is clearer. Please insert "that applies load-responsive protective relays" in R1. "Each Generator Owner that applies load-responsive protective relays shall install settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection." **Response:** The drafting team believes adding the additional "that applies…" within Requirement R1 is duplicative and unnecessary. The Applicability 3.1.1 section clearly identifies the standard and requirement that is applicable to load-responsive protective relays applied by the

Organization	Yes or No	Question 1 Comment
		Generator Owner. For example section 3.1.1 states, "Generator Owner that applies load-responsive protective relays on Facilities listed in 3.2, Facilities." No change made. (2) In the Rationale for R1 please insert this as the second sentence in the third paragraph "Equipment protection takes precedence over loadability, but must be clearly justified if the loadability options in Attachment 1 are not met." These generators are quite valuable and have long repair times so their protection must not be compromised. In its generator protection webinars, NERC emphasized that damaging a generator would harm BES reliability more than tripping on load. Though not exactly comparable, it's clear that restoration time is longer when equipment is damaged (e.g. Hurricane Sandy) than from a blackout (e.g. AZ-CA). **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable fault protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. The drafting team intends that this phrase emphasize that entities must

Organization	Yes or No	Question 1 Comment
		still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) There is potential for double jeopardy with PRC-025-1 and PRC-023-2. PRC-023-2 also applies to relays on GSU transformers under 100kV. Collectively, applicability section 4.2.1.6 and Attachment A, 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." With this proposed standard, a GO/GOP could be found in violation of both PRC-023-2 and PRC-025-1 for not having appropriate relay loadability settings. We strongly suggest that the SDT consider revising PRC-023-2 to remove all references to Generators in order to avoid any possible instances of double jeopardy. This would be consistent with FERC Order 733, paragraph 106, "we think that generator relay loadability, like transmission relay loadability, should be addressed in its own Reliability Standard if it is not to be addressed with transmission relay loadability." If generator loadability is going to be addressed in its own standard, then it should not overlap with transmission relay loadability and PRC-023.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls and elimination of zero-defect expectations). To refocus NERC efforts on compliance, the recent compliance enforcement initiatives would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. We suggest the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this requirement. As an example, what happens if a GO miscalculates their setting or inadvertently uses the wrong setting for one unit? This should not be a violation, per se, if the GO discovers it and corrects it. **Response:** The drafting team considered alternatives such as the "identify, assess, and correct concepts for the proposed PRC-025-1 standard. The drafting team concurred that this standard does not lend itself to this concept because most Generator Owners would not have circumstances that would necessitate the entity to periodically revisit the setting once applied on its load-responsive protective relays. Also, the drafting team believes that the PRC-004 mis-operations standard work will provide an acceptable approach to identify miscalculations. No change made. The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website. (3) We are concerned that this standard also duplicates the proposed PRC-

Organization	Yes or No	Question 1 Comment
		024-1 of Project 2007-09 Generator Verification. Proposed PRC-024-1 requires a GO to ensure its voltage protective relaying does not trip as a result of a voltage excursion. Does the voltage control relaying include Phase-Time Overcurrent Relay (51V) voltage-restrained from Table 1 in Attachment 1 of proposed PRC-025-1? Is the 0.85 pu voltage identified in the same table not a voltage excursion? If so, this duplication needs to be eliminated. **Response:** The drafting team recognized the duplication and coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that the load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made. (4) The standard needs some clear flexibility built into it to deviate from the settings in Attachment 1. Consider an example where a GO sets its phase distance relay on its synchronous generator to meet option 1 and an event causes the unit to trip anyway. The GO should be allowed to reassess and apply an appropriate setting even it if deviates from the Attachment 1 relay settings. **Response:** The drafting team notes that the Requirement R1 does not preclude the Generator Owner from setting its load-responsive protective relays at a more conservative margin than what is required by Attachment 1: Relay Settings. The attachment in the "Pickup Setting Criteria" column or Table 1: Relay Loadability Evaluation Criteria uses phrases such as "shall be set less than" and "shall be set greater than" to accomplish flexibility. No change made.

Response: Thank you for your comments, please see the responses provided above.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	1) R1 states that protection must meet the criteria and be reliable - this is not possible. Protection is often considered an artform, since it includes making compromising decisions between dependability and security. This standard, by its nature, is biased toward security. It requires relays to be set such that they can no longer be depended upon to prevent potential damaging operating conditions. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping <u>is</u> undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) <u>may</u> no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability.

Organization	Yes or No	Question 1 Comment
		For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. 2) In its current form, this standard seems to disregard the factor of time, as it relates to equipment withstand for the specified system conditions. For example, Table 1 will require 51T relays on the GSU not to pickup before 2.2pu (for a machine rated .9pf), even though the transformer through-fault protection curve of IEEE C57.12 does not support continuous operation at that point and the generator stator thermal limit, per IEEE C50.13, is less than 10 seconds. Requiring the GO to permit operation of equipment outside American national equipment standards is incongruent with improving the reliability of the BES. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable <u>fault</u> protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT

Organization	Yes or No	Question 1 Comment
		effective during stressed system conditions. The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards. Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made. 3) In section M1 on pp4/22: reword to "(2) Record Settings" Response: The drafting team has modified the Measure M1 in consideration of your comment and others. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Independent Electricity System Operator	No	a. Requirement R1 seems clear but replacing the word “install” with “implement” or “determine” would seem more appropriate that the settings are not exactly “installed”. If the SDT accepts this proposed change, then conforming changes need to be made to M1 and throughout the entire standard. **Response:** The drafting team has modified the standard to “apply”

Organization	Yes or No	Question 1 Comment
		settings instead of "install" settings. Change made. a. The language in M1 seems unclear to convey the evidence needed to be provided to demonstrate compliance with R1. We suggest M1 be revised to: For each load-responsive protective relay, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed (suggest to replace it with determined or implemented) in accordance with PRC-025-1 - Attachment 1: Relay Settings. **Response:** The drafting team has modified the Measure M1 in consideration of your comment and others. Change made.
Response: Thank you for your comments, please see the responses provided above.		
South Carolina Electric and Gas	No	Entities may have situations where appropriate equipment protection cannot be met and accommodate the load-responsive requirements of Attachment 1. For these rare cases there should be some provision established to allow the Entities to maintain compliance. **Response: The drafting team intends that this phrase emphasize that** entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed

Organization	Yes or No	Question 1 Comment
		on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. The wording of R1 should be changed to clarify that the relay settings applied to load responsive relays must meet or exceed the requirements in Attachment 1. The present wording could be interpreted to require that the load responsive relay settings must be set exactly as prescribed in Attachment 1. **Response:** The drafting team notes that the Requirement R1 does not preclude the Generator Owner from setting its load-responsive protective relays at a more conservative margin than what is required by Attachment 1: Relay Settings. The attachment in the "Pickup Setting Criteria" column or Table 1: Relay Loadability Evaluation Criteria uses phrases such as "shall be set less than" and "shall be set greater than" to accomplish flexibility. No change made.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments, please see the responses provided above.		
Luminant	No	Luminant recommends: 1. The phrase "Each Generator Owner shall install ..." be revised "Each Generator Owner shall set ...". The Generator Owner would only be required to show compliance with the documentation of setting calculations and not required to show a recent test report. **Response:** The drafting team has modified the standard to "apply" settings instead of "install" settings. Change made. 2. The corresponding measure would be revised to read, "The Generator owner shall have evidence such as spreadsheets or summaries of calculations to show that each generator load responsive relay is set according to R1." These recommendations would maintain consistency of requirements and measures with the approach used in PRC-023-2 (Transmission Loadability standard). **Response:** The drafting team has modified the Measure M1 in consideration of your comment and others. Change made. The drafting team considered the application of the suggestion '1' above with respect to '2' for Measure M1. The drafting team considers the suggestion more restrictive.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	Recommend for clarity revising R1 to read: ". . . . . on each load-responsive protective relay (add language: according to its application to maintain) (remove language: while maintaining) reliable protection. . . . . ." If "Rationale for R1" third bullet, term "while maintaining reliable protection" is to be retained, then recommend this term be incorporated

Organization	Yes or No	Question 1 Comment
		into the “Definitions of Terms Used in Standard” on page 2 of 22, of this draft standard package. **Response:** The drafting team has added the word “fault” in the phrase “while maintaining reliable [fault] protection” in Requirement R1. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Pepco Holdings Inc. & Affiliates	No	Requirement R1 and the wording in Attachment 1 require the GO to install settings on “each load responsive protective relay” in accordance with Attachment 1, Table 1. The standard should make it clear that it does not apply to any load responsive relay (i.e., phase overcurrent protection) that is armed only when the generator is disconnected from the system, or enabled only during generator start-up (i.e., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, open breaker flashover schemes, etc.). Nor should it apply to any phase fault detector relays employed to supervise phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) providing the distance element is set in accordance with the criteria outlined in the standard.
Response: The drafting team thanks you for your comment and notes that the application of load-responsive protective relays applicable to the standard only apply while the generator is online. Relays that are armed when the generator is disconnected from the system, enabled during start-up, used for inadvertent energization schemes, open breaker flashover schemes, or and phase fault detector relays are not applicable to the standard. Attachment 1: Relay Settings has been revised to clarify when the load-responsive protective relays are applicable to the standard. Change made.		
Detroit Edison	No	The intent of the requirement is clear, but the specifics of how to accomplish it are not. **Response:** The drafting team is unable to respond absent additional

Organization	Yes or No	Question 1 Comment
		information concerning how to accomplish the requirement. No change made. Not sure of the meaning of “performance” in this context. **Response:** The drafting team adds that “performance,” as used in the comment form question, describes what the Generator Owner actually does to achieve the goal or purpose of the standard. In this case, the “performance” is determining the margins to be used on each load-responsive protective relay according to the application options listed in the Attachment 1, Table 1. No change made.
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	The NSRF is concerned that Measure M1 does not take into consideration situations in which existing relay settings are already in compliance with the standard but the setting calculations are not dated and/or the actual date that the settings were installed is not known. To better align with the risk-based requirement, the NSRF recommends M1 be revised to only require evidence showing that the relays settings were in compliance prior to the enforcement date. M1. For each load-responsive protective relay in accordance with PRC-025-1 - Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed in compliance with Requirement R1.
Response: The drafting team thanks you for your comment and understands that there might be cases where load-responsive protective relays already meet the standard and that specific evidence of compliance may not be readily available; however, the standard’s implementation plan provides ample time for each Generator Owner to assess and document its compliance with the standard. Measure M1 has been modified based on other commenters suggestions.		

Organization	Yes or No	Question 1 Comment
For clarity and other commenters, the drafting team has provided the suggested change to Measure M1 in redline form below for reference only. Note, the only change observed was the additional text colored blue and underline (i.e., "…in compliance with Requirement R1). *M1. For each load-responsive protective relay in accordance with PRC-025-1 - Attachment 1: Relay Settings, each Generator Owner shall have and provide as evidence, dated documentation of: (1) settings calculations, and (2) that settings were installed in compliance with Requirement R1.*		
Entergy Services, Inc. (Transmission)	No	The objectives of the following NERC Standards closely match the objectives of the proposed standard, MOD-024, MOD-025(pending regulatory approval) and PRC-019 (Standard under development). Entergy is currently validating the maximum generator capability under SERC criteria for MOD-024 and MOD-025. This validation requires coordination with applicable load responsive relays.
Response: The drafting team thanks you for your comment and notes that the cited standards referenced operating capabilities and PRC-025 addresses short-term disturbances and that the objectives are not as similar as suggested to be. The MOD standards are dealing with steady state capability. The standard PRC-019 is focused on coordination between AVR control and associated protection setting. The objective in PRC-025-1 is to ensure the field forcing capability of the machine is used to allow the machine to stay on-line for a recoverable system disturbance. No change made.		
Southern Company	No	The requirement is clear - the protective relay setting specifications are not acceptable. We believe that using "apply settings" rather than "install settings" in Requirement R1 better suits the accepted terminology for setting the protective device parameters. **Response:** The drafting team has modified the standard to "apply" settings instead of "install" settings. Change made. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the

Organization	Yes or No	Question 1 Comment
		Guideline and Technical Basis section, may not be compatible with "achieving ...desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, our desired protection level is more conservative so that generation equipment is not allowed to be operated in overloaded conditions. Our experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specificed in Table 1 and not result in undesirable nuisance tripping. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES

Organization	Yes or No	Question 1 Comment
		reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.		
New York Power Authority	No	There was no mention of load responsive relays on an Exciter PPT which is connected to the terminal side of the Generator. There was also no mention of any load responsive relays connected to the ISO Phase Bus between the Generator and the Unit Auxiliary Transformer or the secondary side of the Unit Aux Transformer.
Response: The drafting team notes that the concerns raised relative to relays on an Exciter Power Potential Transformer (PPT) and Isolated Phase Bus (i.e., ISO Phase Bus or IPB) between the generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up transformer, and auxiliary unit transformers (UAT) are within the scope of the standard. No change made.		
PPL and Affiliates	No	Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard.
Response: The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made.		

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	No	1. It will not always be possible to set load-responsive relays according to Attachment 1 criteria without compromising equipment protection. Where this is the case, the standard must allow for technical exceptions. **Response:** The drafting team notes that the entity is expected to provide necessary protection while meeting the requirements of this standard. If legacy approaches do not allow the entity to meet both, other approaches may be necessary. Options have been added to the unit auxiliary transformer (UAT) criteria to allow calculations based on the actual connected auxiliary bus loads and to allow for auxiliary bus performance simulations. For other elements addressed, options have already been provided for the entity to base the protective relay settings on simulated performance. Change made. 2. It should be made clear that entities not using the relay types in Table 1 are by default in compliance with the requirement in R1. **Response:** The drafting team notes that the phrase in Applicability 3.1.1 "that applies load-responsive protective relays…" and at the beginning of Attachment 1, "Each Generator Owner that applies load-responsive protective relays shall use one of the following Options 1-19…" (emphasis added) address your concern by emphasizing that only those relays being applied by the entity are addressed by this standard. No change made. 3. Similar to #2 above, if the entity has Device 21 phase distance relays that have load encroachment logic that removes the possibility of tripping on load, the standard should provide an exemption for R1. **Response:** The drafting team notes that load encroachment logic by itself does not relieve an entity from having to comply with the requirement of this standard. It may, however be useful in attaining the necessary load-responsive protective relay loadability. No change made. 4. Measure M1 should be re-written to improve clarity. We suggest, "…

Organization	Yes or No	Question 1 Comment
		each GO shall have: 1) dated documentation of applicable settings calculations, and 2) dated documentation of the settings above having been applied in the field. **Response:** The drafting team revised the measure to "applied" rather "installed". Otherwise, the drafting team sees no benefit in further modifying the measure as suggested. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Manitoba Hydro	Yes	(1) It is not clear what this question means by the "performance of Requirement R1". If it means that Requirement R1 (and Measure M1) is clear, then yes it is. **Response:** The drafting team adds that "performance," as used in the comment form question, describes what the Generator Owner actually does to achieve the goal or purpose of the standard. In this case, the "performance" is determining the margins to be used on each load-responsive protective relay according to the application options listed in the Attachment 1, Table 1. No change made. (2) R1: The phrase 'while maintaining reliable protection' is extremely ambiguous. We noted that in the rationale, the reader is referred to the Guidelines for elaboration on this phrase. The discussion in the Guideline did little to clarify in our opinion; it discusses balancing the standard and the entity's desired protection plan. Is the standard not mandatory and the entity's overall plan for reliability and protection needs to incorporate the satisfaction of this standard (and others)? **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this

Organization	Yes or No	Question 1 Comment
		standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. (3) M1: The measure as drafted fails to address whether the entity missed installing relays that are required by Attachment A, it is only looking for evidence specifically related to those relays that were installed in accordance with Attachment A. **Response:** The drafting team clarifies that Requirement R1 does not require a Generator Owner to install load-responsive protective relays. The requirement is to install settings in accordance with Attachment 1 where the Generator Owner has applied load-responsive protective relays on its Facilities. Refer to the Applicability section of the standard for additional detail. No change made.
Response: Thank you for your support and comments, please see the responses provided above.		
Operational Compliance	Yes	As long as Guidelines & Technical Basis is included with the standard, so that the phrase "while maintaining reliable protection" is clarified.
Response: The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system		

Organization	Yes or No	Question 1 Comment
operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP ("ICLP") agrees that the instruction is clear in both R1 and M1, but does not agree that the language meets the intent of a "risk-based requirement." The concept, as we understand it, is to focus on the quality of the process which manages the implementation of the settings - not a confirmation that the settings are always perfectly compliant. There is no risk at all inherent in R1, excluding that to the unfortunate Generator Owner who happens to miss-set a single relay. We suggest a preface to R1 similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". This will allow some flexibility when a rare error takes place - while accounting for those entities whose internal controls are not sufficient to the task. In addition, the language addresses those situations where a NERC-compliant setting is not possible without placing equipment or safety at risk.
Response: The drafting team considered alternatives such as the "identify, assess, and correct concepts for the proposed PRC-025-1 standard. The drafting team concurred that this standard does not lend itself to this concept because most Generator Owners would not have circumstances that would necessitate the entity to periodically revisit the setting once applied on its load-responsive protective relays. Also, the drafting team believes that the PRC-004 mis-operations standard work will provide an acceptable approach to identify miscalculations. No change made.		

Organization	Yes or No	Question 1 Comment
The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website.		
Los Angeles Department of Water and Power	Yes	It is clear the Generator must determine and install settings on its load-responsive protective relays in accordance with PRC-025-1.
Response: The drafting team thanks you for your support and comment. No change made.		
ATCO Power	Yes	The requirement is clear enough -- the ambiguities arise in the attachment.
Response: The drafting team thanks you for your support and comment. While no suggestions for improvement were offered the drafting team has restructured Table 1 in an effort to make it clearer. No change made.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
American Electric Power	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
Indiana Municipal Power Agency	Yes	
ReliabiltiyFirst	Yes	
Texas Reliability Entity	Yes	

2. **In response to FERC Order No. 733, paragraph 102, does the Technical Basis and Guidelines provide adequate rationale for the criteria in PRC-025-1 – Attachment 1: Relay Settings? If not, provide additional detail that would improve the rationale for setting load-responsive protective relays.**

Summary Consideration:

The drafting team notes that the FERC Order No. 733, paragraph 102, reference should have been paragraph "108." The drafting team apologizes for this error. For reference the paragraph reads:

108. Finally, the PSEG Companies suggest that the ERO consider whether a ***generic rating percentage can be established for generator step-up transformers*** *and, if so, determine that percentage. Although we [i.e., Commission] do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.*

Approximately 17 commenters representing about 61 entities provided comments for question #2. Ten common themes were revealed by commenters, of those, four represent the majority opinions by comment count and entities represented.

These first two majority comment themes did not result in change to the standard.

(1) Four comments supported by at least 22 entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as "field-forcing" which is a loadability issue, not an overload condition. This duration is within the generator field thermal overload limits raised by these comments. Additionally, there were concerns about why IEEE C37.102 is not adequate and the necessity of the standard. The drafting team contends that IEEE C37.102 represents general protection and that the standard is addressing protection criteria in greater specificity, as well as a regulatory directive related to concerns identified following the August 14, 2003 Northeast blackout.

(2) Approximately three comments supported by at least 25 entities were concerned about the phrase "while maintaining reliable protection" in Requirement R1. The drafting team addressed this through a minor change by inserting the word "fault" to make the phrase "while maintaining reliable fault protection." The standard is conveying that entities must install settings for loadability for the conditions found in Attachment 1 (e.g., depressed voltages) and must also provide the necessary (i.e., reliable) fault protection for equipment. Other similar concerns included the necessity to replace load-responsive protective relays to become compliant with the standard. The drafting team responded to these comments that entities must still "adequately" protect their equipment with regard to faults. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the

standard provides suitable options to address the issue and the drafting team has developed the implementation plan to accommodate an entity that may need to perform modifications to its protective relays or protection philosophies to achieve compliance with the standard and reliable fault protection.

These last two majority comment themes resulted in changes to the standard.

(3) Two comments supported by at least 18 entities were concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

(4) Approximately six comments supported by at least 20 entities revealed a lack of clarity in the basis for the standard. To address this lack of clarity, the drafting team provided detail in the responses below and made minor clarifications in the Guidelines and Technical Basis when the drafting team restructured Table 1 in Attachment 1 based on other comments.

The remaining comment themes were minority issues. The next three resulted in a change to the standard.

(5) Approximately two comments from at least two separate entities raised concerns about what load-responsive protective relays were applicable based on connection or configuration. The drafting team resolved this minority issue by clarifying the Applicability section of standard and adding clarifying text and examples to the Guidelines and Technical Basis.

(6) Approximately two comments from at least two separate entities were concerned that the standard may also apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(7) One comment supported by at least four entities expressed to the drafting team there is a lack of clarity in the application of Attachment 1, Table 1. The drafting team addressed this issue by restructuring Table 1 by Application and Relay Type as well as adding table formatting to draw attention to the various groups of applications and relay types.

The remaining three minority comment themes did not result in a change to the standard.

(8) There was one comment also supported by at least four entities that raised concern that the standard encourages Generator Owners to exceed the manufacturer’s rating of equipment. The drafting team responded to this by explaining that the performance specified

within the standard's criteria does not represent an intentional operating point, but instead represents a natural behavior of generator excitation systems to abnormal system conditions. The Mvar capability is a function of the field-forcing capability of the exciter/field during a system disturbance.

(9) There was one comment supported by at least two entities that raised concern that the standard did not include provisions for a light load condition (i.e., 40%). This condition was originally considered by the drafting team; however, through analysis it was discovered that the second or lighter operating load point offered no additional reliability benefit, only confusion.

(10) One comment by an entity was concerned about the potential overlap between the PRC-024-1 currently under development and the draft PRC-025-1 standard. The drafting team previously identified this issue and coordinated with the PRC-024-1 drafting team to have the load-responsive protective relay references removed from the PRC-024-1 footnote to provide greater distinction between the standards. Also, this entity raised a concern that PRC-025-1 maybe in conflict with standards PRC-019-1. The drafting team reviewed this standard and determined that PRC-019-1 pertains to coordination of applicable protective functions with automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict.

Organization	Yes or No	Question 2 Comment
Ameren	No	(1) We have reviewed in detail our own and SERC-wide performance for the last 6 years, and have not had a single generator protection Misoperation because of relay loadability (for Ameren we cannot recall such an operation in the last 30 years.) It appears that the SDT relies too much on the 2003 blackout single event and empirical data for its justification. While we agree it is desirable to protect the generator and meet the loadability objective, protection equipment changes and/or additions are not justified. **Response:** The drafting team has developed the standard in accordance with the regulatory directives concerning generator relay loadability. The directives are an outcome of the 2003 blackout report and revealed the need to improve generator relay loadability. The goal of the standard is to provide a conservative margin based on generation unit output for which each Generator Owner shall set its load-responsive protective relays. No change made. (2) Please state the total number of generators that tripped in the 2003 blackout to provide proper context. Also, did 2003 blackout post mortem simulations show that had these 28 generators (8 tripped by phase distance and 20 tripped by overcurrent) ridden through the

Organization	Yes or No	Question 2 Comment
		event, the blackout would have been avoided or significantly smaller? **Response:** The drafting team notes that per the 'Power Plant and Transmission System Coordination' – July 2010 – The total number of generators that tripped in the 2003 blackout is 290; eight of those by phase distance and 20 more by 51V protection. Additionally, the cause of tripping for 96 generators is unknown, either because the generator failed to respond to data requests or because the Generator Owner was not able to determine the cause. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) Paragraph 102 of FERC Order 733 does not provide adequate rationale for attachment 1. Paragraph 102 in the Order is discussing Entergy's treatment of GSU and auxiliary transformers. This question is inaccurate and needs to be clarified in order to provide an appropriate answer. **Response:** The drafting team apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made. (2) If the drafting team is referring to paragraph 104, by addressing GSU and auxiliary transformer loadability is addressed in a timely manner and in a way that is coordinated with the outcomes of PRC-023-1, we feel there is more coordination that must be done. Currently, PRC-023-2 is now in effect and potentially has applicability requirements for GSUs and auxiliary transformers. For example, applicability section 4.2.1.6 and Attachment A 1.1 and 1.4 include phase distance and overcurrent relays for transformers that are connected below 100 kV and identified by the Planning Coordinator. There is nothing to prevent the PC from identifying a generator step-up transformer per Attachment B. In fact, if the off-site power supplied to the nuclear plant comes from a specific unit, criterion B3 would compel inclusion of the GSU because it is the circuit that "forms a path." The drafting team must separate the standards to avoid overlap. While we understand that the Commission did not require a separate standard, now that NERC that decided to approach this issue by developing PRC-025-1, it needs to revise PRC-023-2 as well.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. (3) The technical document that is referenced, "NERC Technical Reference on Power Plant and Transmission System Protection Coordination" explicitly states that "there is limited information available that directly addresses which protection functions are appropriate for BES conditions and which were undesired operations." This document is prefaced with the fact that the authors are unsure of what are appropriate settings for protective relays; rather it addresses the coordination of each of the generator protection functions with the transmission system protection. This is not adequate rationale. **Response:** The drafting team notes that since the referenced document was published, additional study has been undertaken, involving 67 simulations of performance of actual generators for the abnormal conditions anticipated by this standard and for the actual conditions observed on August 14, 2003. These simulations have clearly revealed that generators can approach or achieve the level performance specified in the standard and thus not cause a disturbance to deepen. No change made.
Response: Thank you for your comments, please see the responses provided above.		
American Electric Power	No	AEP has the following concerns regarding the settings options. The 0.85 per unit transmission bus voltage will never be seen by Generators with a delta connection to the Generator Step Up transformer. In order to drop the generator bus voltage to support the 0.85 transmission bus voltage, the unit would need to reduce the Real Power output. Even with reducing the Real Power output and increasing the Reactive Power output, the unit may not be able to withstand the lower voltage. Motors may trip out when connected to a lower generator bus voltage, which could cause additional operating issues and potentially leading to a trip of the unit itself.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comment and notes that a system voltage level of 0.85 per unit represents what may be a recoverable system disturbance. The drafting team agrees that generators are unlikely to see 0.85 per unit voltage at the generator terminal. The standard is addressing the natural short-term response of the generator excitation system to such undervoltage conditions. It is entirely likely that the generator will not be able to support this voltage continuously but it will do as much as possible in the period of system recovery. The criteria related to unit auxiliary transformers attempts to address the concern relative to auxiliary bus loads. The concerns raised relative to motors and auxiliary equipment are not within the scope of the project. Only the generator unit, generator step-up transformer and unit auxiliary transformers are within the scope of the standard. No change made.		
South Carolina Electric and Gas	No	Considering Figures 1 & 2, it is unclear whether the intent is to include station auxiliary transformers that feed plant loads when the unit is offline or in the process of startup. **Response:** The drafting team believes the standard provides sufficient clarity to which unit auxiliary transformers (i.e., UAT) load-responsive protective relays are applicable and that an exception is not necessary. Only the unit auxiliary transformers (i.e., UAT) load-responsive protective relays which are used to provide overall auxiliary power to the generator station when the generator is running (i.e., on-line) are applicable to the standard. Refer to the Applicability section (3.2.3), the accompanying footnote #1 and the unit auxiliary transformers section of the Guidelines and Technical Basis for additional information. No change made. An exception should be made for transformers that do not feed plant loads during normal unit online operation. **Response:** The drafting team notes that in Section 3.2.3 of the Applicability section and the related footnote 1 "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." addresses this issue. No change made.
Response: Thank you for your comments, please see the responses provided above.		
New York Power Authority	No	For the Unit Auxiliary Transformer, the Technical Basis and Guidelines does not take into account the 51 element being set below 150% of rated but with a significant time delay

Organization	Yes or No	Question 2 Comment
		setting to provide backup protection for the feeder protection.

Response: The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made.

The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change **made.**

The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards.

Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made.

The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made.

Organization	Yes or No	Question 2 Comment
ATCO Power	No	I think you are trying to handle the case where the transmission system voltage becomes depressed to 0.85 pu. This does not cause the voltage at the armature terminals of the generator to change, except in a transient time frame (or if the AVR is in manual or drooped). During the transient time frame, the armature terminal voltage would be depressed to 1-(0.15 * (Xd'/(Xd'+Xt)) pu volts (Xt=transformer reactance (pu), Xd'=transient machine reactance, pu), but this will reduce, not increase, the reactive power output, so the worst case for voltage support is in the steady-state time frame after the AVR corrects the

Organization	Yes or No	Question 2 Comment
		voltage. After the AVR corrects the voltage, the armature terminals will return to approximately 1 pu voltage (or whatever it was set at before the disturbance) and the VAR outflow will be the transformer MVA times 0.15/%IZ (0.15 = 1-0.85 = amount voltage is depressed, %IZ transformer rated impedance). (This is just Ohm's law applied to the voltage difference across the output transformer between 1 pu armature voltage and 0.85 pu system voltage.) There is no reason to require simulations to find this value; it can be easily calculated. (The 150% assumption is another way of saying, "assume the output transformer impedance is 10% on a base of the generator maximum real power" -- and it often isn't.) If you want to be sure to cover all possible real power loadings, draw a horizontal line across the PQ plane parallel to the P axis at this value. (This is true unless we assume a voltage depression will only happen at certain loadings -- why? which ones?) This horizontal line corresponds to a mho circle with a diameter equal to Xt/0.15, 90 degrees MTA, and zero offset. So if the goal is, "permit generators to ride through 0.85 pu transmission voltage depressions without tripping on 21 relays", then require that 21 settings lie inside a mho circle with a diameter/reach of Xt/(0.15 * 1.15), 90 degrees MTA, and zero offset. (The 1.15 is the 115% calibration fudge factor.) The technical basis does not support asking for more than this, and asking for less will not accomplish the apparent objective unless we can somehow guarantee that we don't care about spurious trips at certain loadings (which may be due to power swings.) In my opinion, analysis should precede simulation.
Response: The drafting team thanks you for your comment and notes that a system voltage level of 0.85 per unit represents what may be a recoverable system disturbance. The Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing shall not be inhibited from operations during the event. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. No change made.		
Duke Energy	No	It is difficult to comment on the criteria, as we are not familiar with the train of thought used to derive them. Not all of the criteria are described in the Technical Basis section.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the		

Organization	Yes or No	Question 2 Comment
available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
Luminant	No	Luminant agrees that a reasonable approach was used to define limits based on unit MVA ratings for relays susceptible to load. However, the drafting team does not address the coordination of the relay with transmission relaying as described in FERC Order 733, paragraph 107. The Commission directed the ERO to address relay loadability that facilitates the reliability goal of ensuring coordination between transmission and generator protection systems, as required by PRC-001 (draft standard PRC-027). Luminant recommends adding Transmission Owners to the Applicability Section and include relay coordination with the Transmission Owner for each applicable load responsive relay as a separate requirement and measure.
Response: The drafting team thanks you for your comment and notes that relay coordination is not applicable because the standard does not involve timing elements which would require coordination with other reliability functions. No change made.		
Los Angeles Department of Water and Power	No	Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). **Response:** The drafting team notes that that referring to the posted standard that Options 1-4 (now Options 1a, 1b, 1c, and 4) apply to each generator unit and Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). Each option in Table 1 provide the specific Pickup Setting Criteria (i.e., margins) for the load-responsive protective relay types (i.e., time overcurrent, distance, etc.) in the Relay Type column; for generators (i.e., synchronous or asynchronous) specified in the Application column at a voltage corresponding to the criteria used in the Bus Voltage column. No change made. For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes that Figures 1 and 2 are examples of unit auxiliary transformer (UAT) connection configurations. No change made.
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	Recommend the phrase "while maintaining reliable protection" be removed as it introduces ambiguity into R1. Although the SDT attempts to clarify the phrase within the "Guidelines and Technical Basis", the NSRF is concerned that the phrase's inclusion will only result in future requests for Interpretation as entities are forced to explain and defend their desired protection goals. Rather than rely on the "Guidelines and Technical Basis", we recommend the following changes to R1 be made: R1. Each Generator Owner shall install settings that are in accordance with PRC-025-1 - Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable protection.
Response: The drafting team thanks you for your comment and has added the word "fault" in the phrase "while maintaining reliable [fault] protection" in Requirement R1. Change made. The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made.		
Pepco Holdings Inc. & Affiliates	No	Section 3.1 and Appendix E of the NERC SPSC Technical Reference Document "Power Plant and Transmission System Protection Coordination" describes two separate loading points that should be examined to ensure adequate generator relay loadability during extreme system conditions. One is the loading condition chosen in PRC-025-1 (MW = rated MW ; MVAR = 1.5 x rated MW). The other loading condition is with a lower power output, but with a higher var output (MW= 0.4 x rated MW ; MVAR = 1.75 x rated MW). The SPCS document illustrates that depending on the maximum torque angle setting of the distance element that this second loading condition may become the limiting criteria. The Technical Basis and Guidelines in PRC-025-1 refers to this SPCS document several times, but it does

Organization	Yes or No	Question 2 Comment
		not mention this second loading condition, or the rationale for ignoring it when developing the chosen setting criteria.
Response: The drafting team removed the 40% (i.e., light loading) point from the standard following further simulation. Analysis determined the 40% load point did not change the outcome of the standard being based on the 100% (i.e., full load) load point of generation unit's nameplate rating. The 100% load point achieves an overall conservative margin for setting load-responsive protective relays on generators. This determination is reflected in the team's August 30, 2012 Meeting Notes posted on the NERC website project page. No change made.		
ReliabiltiyFirst	No	The criteria are much more restrictive than that of the IEEE C37.102 recommendations. As the guide states in regards to a general distance setting of 150 to 200% of the generator MVA rating, "However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." Some of the options for phase distance protection may severely restrict the remote backup protection from the generator. The criteria may prevent the generator backup protection from seeing uncleared faults on the remote ends of lines connected to the plant. It is also not clear whether load encroachment methods would work as referenced in the guidelines since the angle of power flow may be near 60 degrees. Load encroachment at these high angles would cut out most of the reach characteristic and allow little margin for detecting arcing. **Response:** The drafting team notes that whether or not load encroachment or blinders are effective requires a case by case analysis. If this approach is used, the entity must determine the generator unit's ability to operate at all load levels. No change made. The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during

Organization	Yes or No	Question 2 Comment
		stressed conditions to the extent possible. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Southern Company	No	The rationale seems to ignore the fact that most generators do not operate any of their equipment beyond the manufacturer's ratings in overloaded conditions. The practices suggested by Table 1 seem to be patterned on transmission line loading practices, which are different than the practices used by generators. **Response:** The drafting team notes that the Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing that will occur during abnormal system conditions is not affected by compromised equipment. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. The drafting team does not believe that entities will change settings when the unit is de-rated. No change made. Generator step up transformers and station auxiliary transformers are generally not allowed to be subjected to short term overload conditions. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. We disagree with the suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing philosoply of protection used by many companies has proven (over multiple decades) to be adequate for protecting

Organization	Yes or No	Question 2 Comment
		our equipment and providing reliable power supply to customers. **Response:** The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made. The NERC Glossary states the following definition for Equipment Rating: "The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner." The acceptable amount of risk to power equipment evident through margin in the protection settings rests with the equipment owner. We are concerned that the NERC standards will take this away from the equipment owner. This is especially concerning where automatic protection is required and must operate quickly to prevent significant major equipment damage. Reliance on operator intervention to protect the equipment, in this case, is not practical. Adequate margins of protection must be allowed to be maintained in the automatic trip settings. We believe adequate protection is a fundamental tenet for BES reliability to ensure the equipment can be restored to service quickly. **Response:** The drafting team intends that this phrase emphasize that entities must still “adequately” protect their equipment. However, an entity may need to perform

Organization	Yes or No	Question 2 Comment
		modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	The Standard Drafting Team needs to revisit this question. Reviewing the PRC-025-1 SAR, Attachment 1, Order No 733 - Action Plan and Timetable, paragraph 102 is not listed as a significant paragraph of Order 733, or for this standard. FERC Order 733, p102, is a comment from Entergy. Reviewing supporting PRC-025-01 background information on the NERC website, there is no reference to FERC Order 733, p102. This question needs to be re-asked with correct FERC Order references.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comments and apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made.		
Detroit Edison	No	With the exception of Auxiliary Transformers, this standard appears to be concerned with relay elements that operate for power flow toward the transmission system. Distance elements and directional overcurrent relays not "looking" toward the transmission system should not be in scope. Perhaps a statement to this effect in the Technical Basis would be beneficial.
Response: The drafting team thanks you for your comments. The 21 (and 67 – added in draft 2) relay function is directional toward the transmission system in the standard. No change made.		
PPL and Affiliates	No	1. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. ***Drafting team observation:*** *PPL changed the phrase NAGF's comment #6 found in Question #5, "whether or not our calculations," to "whether our calculations." Please see response below.* 2. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new

Organization	Yes or No	Question 2 Comment
		requirements. ***Drafting team observation:*** *PPL #2 is consistent with NAGF's comment #6 found in Question #5. Please see response below.* 3. This is not a minor concern. In addition to the thermal damage posed in some cases by the proposed PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. ***Drafting team observation:*** *PPL #3 changed the phrase in NAGF's comment #6 found in Question #5, by adding "the proposed" making "cases by [the proposed] PRC-025-1." Please see response below.* 4. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. ***Drafting team observation:*** *PPL #4 is consistent with NAGF's comment #6 found in Question #5. Please see response below.* 5. Consistent with FERC's March 15, 2012 FFT Order, standards or requirements should not be adopted that have little or no effect on reliability or because of costs that are not justified by the reliability benefits. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an requirement is applicable, imposing burdens with little or no identifiable benefit for perhaps 80% of all NERC-registered units. ***Drafting team observation:*** *PPL #5 has made non-substantive changes to phrases used in NAGF's comment #6 found in Question #5, and has not changed the nature of comment."*

Organization	Yes or No	Question 2 Comment
		Please see response below. 6. An exception should be made similar to the one proposed in PRC-024 R3 of the generator verification standards and should state, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." ***Drafting team observation:*** *PPL #5 has made non-substantive changes to phrases used in NAGF's comment #6 found in Question #5, and has not changed the nature of comment." Please see response below.*
Response: The drafting team thanks you for your comments. PPL and Affiliates has submitted, except as noted by the drafting team the same comments #1 through #6 above, as those prepared by the North American Generator Forum (NAGF) comment #6 found in Question #5 below. Please refer to drafting team's response to NAGF's comment #6 below in Question #5.		
Ingleside Cogeneration LP	Yes	From a technical perspective, Ingleside Cogeneration found this section was soundly grounded. However, we believe that there is no rational basis that the standard apply to generators which have minimal impact on BES reliability - analogous to the 200 kV voltage threshold for transmission lines in PRC-023-2. The justification needs to be captured in the Technical Basis and Guidelines section, although the criteria itself would appear in the Applicability section. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. The drafting team considered approaches to limiting the applicability but determined that "minimal impact" is a superfluous term that the standard should be applicability to all BES generators. No change made.

Organization	Yes or No	Question 2 Comment
		Secondly, there needs to be further discussion concerning the interaction of the relay loadability thresholds with those required under Project 2007-09 Generation Verification - particularly PRC-024-1 and PRC-019-1. At present, every one of these standards are written in a manner that calls for the Generator Owner to comply with their requirements, and to figure out how to make them all work together. Even though we agree that the ultimate goal to improve generator availability will greatly serve BES reliability, ICLP does not believe this kind of approach is reasonable - and may lead to violations even when the GO is heavily committed to the task. **Response:** The drafting team notes that PRC-019 is focused on coordination between AVR control and its protection setting. The objective in PRC-025-1 is to ensure the field forcing capability of the machine is used to allow the machine to stay on-line for a recoverable system disturbance. The drafting team recognized the duplication and coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that the load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made.
Response: Thank you for your support and comments, please see the responses provided above.		
Wisconsin Electric Power Company	Yes	
Manitoba Hydro	Yes	No comment.
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards	Yes	

Organization	Yes or No	Question 2 Comment
Development Team		
Dominion	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
Tacoma Power	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	

3. **Does <u>PRC-025-1, Attachment 1: Relay Settings, Table 1</u> clearly identify the criteria for setting load-responsive protective relay types for each Option 1 through 17? If not, provide specific detail that would improve the clarity of Table 1.**

Summary Consideration:

Approximately 22 commenters support by at least 63 entities provided comment for question #3. There were at least 14 common themes presented by commenters, of those, about three comments represented the majority opinions by comment count and entities represented.

The first three majority comment themes resulted in changes to the standard.

(1) More than 30 comments supported by at least 40 entities were concerned about how to perform calculations, a lack of clarity in the Attachment 1, how to address different conditions such as varying generator output, and the need for figures and examples. The drafting team addressed these concerns by clarifying Attachment 1, rewriting the Guidelines and Technical Basis to coincide with the various options available to entities, and providing a series of calculations for the options.

(2) Approximately nine comments supported by at least 37 entities expressed to the drafting team there is a lack of clarity in the application of Attachment 1, Table 1. The drafting team addressed this issue by restructuring Table 1 by Application and Relay Type, as well as adding table formatting to draw attention to the various groups of applications and relay types.

(3) Approximately seven comments supported by at least 13 entities expressed concern about overload conditions on equipment and revealed confusion about the duration being addressed by the standard. The drafting team made minor clarifications in the Guidelines and Technical Basis to further explain that the standard covers the duration known as “field-forcing,” and is a relay loadability issue, not an overload condition. This duration is within the generator field thermal overload limits raised by these comments. Additionally, there were concerns about why IEEE C37.102 is not adequate and the necessity of the standard. The drafting team contends that IEEE C37.102 represents general protection and that the standard is addressing protection criteria in greater specificity, as well as a regulatory directive related to concerns identified following the August 14, 2003 Northeast blackout.

The remaining 11 comment themes were minority issues and the next six discussed here did not result in changes to the standard.

(4) About three comments supported by at least eight entities were received questioning the basis for including equipment like the unit auxiliary transformers (UAT) and questioning why out-of-step protective relays were not included in the standard. The drafting team responded that UAT facilities are included to address a regulatory directive and out-of-step relays are subject to the next phase of this project which will be Project 2010-13.3 – Stable Power Swings (Phase III).

(5) Two comments supported by at least 10 entities suggested greater flexibility in setting their load-responsive protective relays. The drafting team responded that the standard by the use of options has provided this flexibility. To determine settings, an entity may select a simple calculation, a more complex and precise calculation, or the most precise method using simulation. Additionally, the standard provides each entity the ability to set its load-responsive protective relays to exceed the values required by the Table 1 in Attachment 1.

(6) Two comments supported by three entities questioned why the standard did not follow the format of standard, PRC-023-2 – Transmission Relay Loadability. The drafting responded that for transmission loadability a wide variety of topologies affect the loadability resulting in many different criteria. Generating plant relay loadability is instead affected by the innate capability of the generator resulting in a smaller set of available criteria. Also, that the criteria specified in PRC-023-2 – Transmission Relay Loadability would not support the short-term performance that will be observed by generation plants for system disturbances and would therefore result in undesired trips of the generating plant.

(7) There were two comments supported by at least three entities that raised concern that the standard did not include provisions for a light load condition (i.e., 40%). This condition was originally considered by the drafting team; however, through analysis it was discovered that the second or lighter operating load point offered no additional reliability benefit, only confusion.

(8) Two comments supported by at least three entities raised concern that PRC-025-1 maybe in conflict with standard PRC-019. The drafting team reviewed this standard and determined that PRC-019 pertains to coordination of applicable protective functions with automatic voltage regulator (AVR) control (i.e., limiters) applications and has no observed conflict.

(9) Two comments supported by at least eight entities were concerned that entities may need to perform modifications to their protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team did not make any changes to the standard based on this concern, because the standard provides suitable options to address the issue and the drafting team has developed the implementation plan to accommodate that an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard.

The remaining five minority comment themes were issues that resulted in changes to the standard.

(10) Three comments supported by at least six separate entities raised concerns about how to determine if load-responsive protective relays were applicable based on connection or configuration. The drafting team resolved this minority issue by clarifying the Applicability section of standard, modifying Table 1, and adding examples to the Guidelines and Technical Basis.

(11) Approximately four comments supported by individual entities raised concerns about the calculation of the settings based on seasonal output capability. The drafting team addressed this through a clarification in Attachment 1, Table 1. The calculation for Real Power output is the MW capability reported to the Planning Authority or Transmission Planner and the Reactive Power output, in Mvar, is based on the MW value derived from the generator unit's nameplate MVA at rated power factor times 150%.

(12) Two comments supported by at least six entities suggested changing the IEEE function numbers for voltage-restrained (e.g., 51V) and voltage-controlled (e.g., 51VC) protective relays to the nomenclature V-R and V-C for greater clarity and consistency. The drafting team agreed and made the change throughout the standard.

(13) Two comments supported by at least five entities were concerned that the standard may apply to those protective functions for conditions such as inadvertent energization, or flashover schemes. The drafting team revised the standard and provided substantial details in Attachment 1 about the conditions that are exceptions to the standard. See Attachment 1 for the exhaustive list of conditions not applicable to the standard.

(14) Approximately three comments supported by individual entities raised concerns about a lack of clarity in dealing with generator step-up (GSU) transformer winding taps, on-load tap changers (OLTC), and no-load tap changers (NLTC). The drafting team addressed these comments by providing example calculations and additional text in the Guidelines and Technical Basis.

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	No	(1) For all 21 - Phase Distance Relays (Option 1 - 4 and Option 13 - 16): The setting criteria did not mention the maximum reach angle of the impedance element setting. Should this be considered and clarified? **Response:** The drafting team notes that the maximum reach angle is based on the characteristics of the protected equipment and is left to the user to determine. No change made. (2) For 51V - Phase Time Overcurrent Relays, voltage-restrained, (Option 5 & 6): Following this setting criteria could make detecting faults on the high side of the step-up transformer very difficult especially considering that transient or synchronous machine impedance (X'd or Xd instead of X"d) is used for fault calculation. **Response:** The drafting team notes that, if the entity discovers that the relay cannot be used to provide protection and to meet the standard, alternate protection strategies should be pursued. No change made. (3) For the 51 relays on the step-up transformers (Option 10): Following this setting criteria could mean that the pickup setting could be 175% of nameplate rating of the transformers. Should there be any concern with the transformer overload and mechanical damage as a

Organization	Yes or No	Question 3 Comment
		result? Also, the 175% setting is not consistent with the 150% number in the Transmission Relay Loadability standard. **Response:** The drafting team removed the 40% (i.e., light loading) point from the standard following further simulation. Analysis determined the 40% load point did not change the outcome of the standard being based on the 100% (i.e., full load) load point of generation unit's nameplate rating. The 100% load point achieves an overall conservative margin for setting load-responsive protective relays on generators. This determination is reflected in the team's August 30, 2012 Meeting Notes posted on the NERC website project page. No change made. (4) The "Bus Voltage" criteria are not clearly defined and should be clarified. For example, in Option 1, the generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage would vary depending on the current going through the transformer. Also, option 2 in the table makes reference to "on the high side" and option 1 in the table makes reference to "of the high side". Should these all read 'of'? **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.

Organization	Yes or No	Question 3 Comment
		(5) Given 'gross MW' and 'terminal voltage', how would we calculate current in order to calculate the generator bus voltage? **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (6) What is meant by "maximum seasonal gross MW"? Is this the nameplate MW? Is this the MW calculated for MOD-024? If so, a reference should be made to this standard. **Response:** The drafting team notes that Attachment 1 has been revised to add "capability" reported to the Planning Coordinator or Transmission Planner. If the gross MW capability reported to the Planning Coordinator or Transmission Planner varies seasonally, the drafting team intends that the highest of the various seasonal capabilities be used by the Generator Owner. If from year to year the capability for any specific season varies the entity may need to reevaluate their protection if the newest maximum gross MW capability has increased from that previously used. The drafting team does not anticipate that entities will unnecessarily change settings if the maximum gross MW capability decreases. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Ameren	No	(1) The first sentence implies that only "one" of the 17 Options needs to be met. Actually Option 17 almost always must be met as well as one of the first 16 Options. In cases using different relay types for the generator two of the first 16 Options need to be met. **Response:** The drafting team notes the first sentences states that the Generator Owner shall use "one of the following Options 1-17 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay according to its application." Only one option may be used per load-response protective relay according to its application. The drafting team has re-arranged the table and the option numbers have changed. (2) Our reading is that the 115% is applied to the loading criteria prior to calculating the impedance or current Pickup Setting Criteria. An example for Options 2 and 5 would

Organization	Yes or No	Question 3 Comment
		provide clarity and help reach your loadability objectives without trapping the GO into unintended non-compliance. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (3) Our reading is that Bus Voltage instructions for Option 1 ignore the IZ voltage rise through the GSU but include it for Option 2. Is that the SDT's intention? **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. (4) The last part of p 7 paragraph 2 states the Reactive Power capability is calculated at rated power factor (typically 0.8 to 0.9) which conflicts with the Table 1 Pickup Setting Criteria which uses Reactive Power equal to 150% of rated MW. We suggest to correct this discrepancy.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes that the second paragraph in Attachment 1 has been corrected. Change made. (5) PRC-023 provides a wider range of criteria for meeting transmission loadability. **Response:** The drafting team notes that for transmission loadability a wide variety of topologies affect the loadability resulting in many different criteria. Generating plant relay loadability is instead affected by the innate capability of the generator resulting in a smaller set of available criteria. No change made. (6) An entity may be forced to reduce the Real Power capability it reports to the Planning Coordinator in order to meet the standard as proposed. This would have an adverse impact on BES reliability. **Response:** The drafting team does not believe that an entity would find it attractive to reduce generator capability but instead would perform protective system modifications as necessary to achieve the requirements of the standard. No change made.
Response: Thank you for your comments, please see the responses provided above.		
ACES Power Marketing Standards Collaborators	No	(1) We find the criteria confusing and needing further clarification. First, we suggest dividing the table into multiple tables based on the relay type and application. This will make it clear that GO does not have 17 options but rather has only three options for Phase Distance Relays (21) protecting synchronous generators. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. Second, we are confused about the difference in the bus voltage column for options 1 and 2. Both options apply to the generator bus and voltage is calculated from the high side of the generator step up (GSU) voltage. Option 1 allows the voltage to be set at 0.95 pu and

Organization	Yes or No	Question 3 Comment
		option 2 allows the voltage to be set at 0.85. Option 2 mentions using the GSU impedance in addition to the turns ratio to calculate the generator bus voltage from the high side whereas option 1 only mentions the turns ratio. If the intention is to include the GSU impedance in one calculation and not the other, does it make sense to have a voltage difference of 10%? To drop voltage 10% across a GSU would require a very high impedance transformer. Please provide further clarification. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. As currently defined, we believe that option 1 will always be selected because it is simply less restrictive. We note that similar issues exist between Options 5 and 6 and Options 13 and 14. We assume the voltage identified in the bus voltage column of options 10-12 applies to the generator bus. It is not clear if the impedance of the GSU is to be considered for these options. We assume it would be but there is so much less information provided than in the other options so it is not clear and is not explained in the technical guidelines. **Response:** The drafting team believes that Option 2 (now 1b) while more complex may provide a less restrictive setting, not Option 1 (now 1a). No change made.
Response: Thank you for your comments, please see the responses provided above.		

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Affiliates	No	1) Options 1, 5 and 13 should be eliminated, or a qualification should be added that these options may only be used if the generator step-up transformer reactance is greater than some specified threshold amount. It is true that due to the voltage drop across the transformer, the generator voltage will be higher than the system voltage. This can be seen from the following equation: Vgen = Vsys + Igen x (j Xt). Assume the generator is operating at a loading condition of S = 1.532@56.31 pu MVA, which is the maximum anticipated loading condition identified both in this standard, as well as in the SPCS document (ref. Appendix E). Assume the generator voltage Vgen is 0.95@0 pu, as allowed in Options 1, 5, and 13. Since S = VI*, Igen can be found as 1.613@-56.31 pu. By then solving for Vsys, one can see that Vsys will be greater than 0.85 pu, whenever Xt is smaller than 0.076pu (Xt < 7.6%). While most GSU transformers have a reactance equal to, or greater, than this value, some may not. Since all loadability criteria must be based on a system voltage of 0.85 pu, the choice of Vgen = 0.95 pu is appropriate only if the application is restricted to GSU's with sufficient reactance to ensure the application results in a corresponding system voltage of 0.85 pu, or lower. Options 2, 3, 6, 7, 14, and 15 are not an issue, because they assume a system voltage of 0.85 pu and then require a calculation, or simulation, to obtain the corresponding generator voltage to be used in the evaluation. Finally, if the SDT decides to retain Options 1, 5, and 13 then the Guidelines and Technical Basis section should be revised to address the technical justification for the choice of a 0.95 pu generator voltage. **Response:** The drafting team believes the settings calculated in options 1, 5 and 13 are reasonable proxies for options 2, 6 and 14 (now 1b, 2b, and 7b), respectively and for those entities who wish to use options 1, 5 and 13 (now 1a, 2a, and 7a)will represent a considerable simpler calculation. No change made. 2) The ANSI number 51V-R should be used instead of 51V to represent voltage restrained overcurrent relays, and 51V-C should be used instead of 51C to represent voltage controlled overcurrent relays. Using 51V-R and 51V-C avoids confusion, since 51V is often used to represent both types of relays. Also the 51V-R and 51V-C terminology is consistent with

Organization	Yes or No	Question 3 Comment
		that used in the SPCS Technical Reference Document. **Response:** The drafting team agrees that using V-R for voltage restrained and V-C for voltage-controlled relays as used in the NERC Power Plant and Transmission System Protection Coordination document adds clarity; therefore, has modified the standard as suggested. Change made. 3) In the Guidelines and Technical Basis portion of the standard it states "If a mho phase distance relay cannot be set to maintain reliable protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics." However, the standard does not provide any specific criteria, or methodology, on how to evaluate relay loadability if these techniques are employed. Table 1 simply states that the 21 element (assumed to be a non-offset mho element) should be set with a maximum reach less than the apparent impedance described, apparently regardless of the setting of the maximum torque angle of the relay. If blinders, or load encroachment techniques were used to accommodate the one specific loadability point described in the standard, aren't there other loadability constraints that also need to be addressed? **Response:** The drafting team notes that the standard defines the loadability constraints that must be addressed to meet the objective of the standard. No change made. The Technical Basis portion of the standard points out the concern that altering the shape to achieve a longer reach may restrict the capability of the unit when operating at a real power output other than 100%. Therefore, to cover all applications, the PRC-025-1 standard should describe loadability criteria irrespective of the type, or shape, of the impedance characteristic used. To accomplish this, perhaps a better set of setting criteria would be as follows: "The phase distance protective characteristic should be set, assuming a generator voltage as specified in the column labeled bus voltage, so as to not operate under any of the following three

Organization	Yes or No	Question 3 Comment
		loading conditions: a) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (100% of Maximum MW; Reactive Power equal to 150% of rated MW). b) Generator supplying power (as measured at the generator terminals) equal to 1.15 times (40% of Maximum MW; Reactive Power equal to 175% of rated MW). c) Generator supplying power (as measured at the generator terminals) within its published capability curve." **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made. Plotting these three constraints on the R-X impedance plane would allow one to choose a phase distance characteristic (with, or without, load encroachment, or blinders) that would be immune from operating under these specific loading conditions. The third condition would effectively limit the reach of the element so as to not restrict the reactive capability of the unit. This last issue is very important, since in the latest draft of PRC-019 the coordination of the phase distance element with the generator reactive capability curve was specifically removed, implying that it would be addressed in the PRC-025 loadability standard. **Response:** The drafting team notes the PRC-025-1 is not for the fault or steady state condition, but for the field-forcing condition (short-term). Coordination with AVR response is anticipated to be covered by PRC-019 currently in development and coordination with the transmission system is covered by the existing PRC-001-1 and PRC-027-1 which is under development. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Nebraska Public Power District	No	1) Table 1, Option 1. "Generator bus voltage corresponding to .95 pu of the high side nominal voltage times the turns ratio of the generator step-up transformer". For example,

Organization	Yes or No	Question 3 Comment
		one of our plants GSU has a high side of 345kv nominal and has a generator nominal voltage of 23kv. Do we assume 345kv/23kv = 15 ratio or do they use the actual ratio which has a tap of 345 and tap of 23.4 = 14.74 ratio. One Generator voltage could be 0.95 x 345 / 15 = 21.85 kv or the Generator voltage could be 0.95 x 345 / 14.74 = 22.24kv. Do we use the Generator bus voltage of 21.85kv, 22.24kv, or is the calculation wrong. If this can be clarified or an example provided this would be helpful. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 2) Table 1, Option 1. "The impedance element shall be set less than the impedance derived from 115% of: (1) Real Power output - 100% of maximum seasonal gross MW reported to the Planning Coordinator, and (2) Reactive Power output - a value that equates to 150% of rated MW. Can you give an example calculation. Our unit is a 757MVA unit. Lets assume our maximum Seasonal gross MW is 650MW. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. i. Real Power is 650MW ii. Reactive Power is 975MVAR iii. MVA = 1.15 x SQRT (650 x 650 + 975 x 975) = 1348 MVA at 56 degrees. Do we find the impedance of this MVA value at 56 degrees and the 0.95 bus voltage? If this can be clarified or an example provided this would be helpful. The KD 21 relay is a 75 degree relay so how do we account for the power factor of the relay, power factor of load, and power factor from the MVA with your table. Can you give an example calculation? **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 3) Table 1, Option 10. Can you give an example calculation for option 10. How is an

Organization	Yes or No	Question 3 Comment
		overcurrent affected by voltage? For a 757MVA, 23KV the FLA is 19,002 amps. Can you give an example for setting the 51 relay. Do we calculate the MVA as shown in step 2.iii above then use the 0.85 x (345 / 15) or 0.85 x (345 / 14.74) to obtain the generator voltage so we can calculate the current once the MVA is known. Why are we not selecting 1.5 x FLA. The FLA does not change based on per unit voltage. If this can be clarified or an example provided this would be helpful. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: The drafting team provides the following additional information. 1. The key here is “0.95 per unit of the high side nominal voltage times the generator step-up transformer turns ratio”. In this example, 22.24 kV would be used. 2. One would find the magnitude of the complex impedance at 1348 MVA, and adjust the power factor angle (PFA) to the relay maximum torque angle (MTA) by dividing the resulting impedance (either primary or secondary) by the term, “cosine(MTA-PFA).” This will produce a mho relay reach (circular characteristic at its MTA) that will go through the complex impedance value at its PFA. 3. The intent here is the Real Power output (in MW) and the specified Reactive Power output (in MVar) would result in a complex power output (in MVA), that would be translated to amperes at the specified voltage (rather than at rated voltage). It has been the intent of the drafting team to further develop the supporting documents as needed by industry.		
Duke Energy	No	1) If such a table is used; RELAY TYPE should simply be the type of element, such as "Phase Distance - 21", and APPLICATION should be the elements use, such as "Applied on synchronous generator, set to trip for faults in the system direction." Further, the SDT should not separate BUS VOLTAGE and what is called PICKUP SETTING CRITERIA - Together these are defining the system conditions for which the relay is not supposed to pickup. **Response:** The drafting team has restructured the table for clarity. The bus voltage column describes the system behavior to which the option applies. Change made. 2) It is not clear what the intent of the 115% factors specified in Table 1 are. If these are for

Organization	Yes or No	Question 3 Comment
		coordinating margin, this should be expressed so coordination margins are not doubled. **Response:** The drafting team notes that the 115% factor is the margin required within the standard. An entity may choose to apply additional margin if they wish. See the Guidelines and Technical Basis section in the standard. No change made. 3) We recommend using the common designations of 51VC for voltage controlled inverse time overcurrent elements and 51VR for voltage restrained inverse time overcurrent elements. **Response:** The drafting team agrees that using V-R for voltage restrained and V-C for voltage-controlled relays as used in the NERC Power Plant and Transmission System Protection Coordination document adds clarity; therefore, has modified the standard as suggested. Change made. 4) SDT should specify criteria in standard engineering terms. The use of language such as "VArs equal to 150% of rated MW" is not clear. It would be better to specify "Rated Watts at .55 pf lagging." **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 5) We do not understand the differences between several of the options, such as between option 1 & 2. Option 1 is not aligned with Appendix E of the technical guide, and no commentary is provided within the standard. SDT is creating criteria that are outside the mainstream - it must provide more technical information on what the intent and rationale is for each criteria. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar.

Organization	Yes or No	Question 3 Comment
		For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). The drafting team used the document to which you refer as a base document, and altered the criteria in two specific areas: the drafting team determined that the low-power operating point did not meaningfully contribute to reliability and chose to not include it, and also provided a third optional criteria (option 1) which results in even more simple calculations if the entity chooses to use it. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. The drafting team notes that the drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 6) The intent of options 13-16 is not clear. Are these for 21 elements on the high voltage of GSU? If so, why are generator terminal voltages mentioned? **Response:** The drafting team notes that that referring to the posted standard that Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). No change made. 7) We question whether all of the options are required. Many of the system conditions are

Organization	Yes or No	Question 3 Comment
		the same from one application to another. Could the worst case system conditions be presented in paragraph form along with descriptive commentary? **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The drafting team further notes that the Generator Owner shall for each load-responsive protective relay that it applies on BES facilities set be set according to the standard. 8) SDT should consider including recommendations for the traditional 50/27 elements used for inadvertent energization protection. Traditionally the 50 elements of this type are set near 1.5pu. The setting of the voltage element needs to be evaluated such that it will ride through disturbances but also sense voltage during a true inadvertent energization under worst case system conditions. Perhaps these elements should be considered as specialized forms of 51VC. These elements will also need to comply with PRC-025 LVRT criteria. **Response:** The drafting team notes that the application of load-responsive protective relays applicable to the standard only apply while the generator is online. Relays that are armed when the generator is disconnected from the system, enabled during start-up, used for inadvertent energization schemes, open breaker flashover schemes, or and phase fault detector relays are not applicable to the standard. Attachment 1: Relay Settings has been revised to clarify when the load-responsive protective relays are applicable to the standard. Change made. 9) In reference to Option 17: 150% of the maximum transformer rating can be 250% of the base rating. Transformers are not rated to carry 250% continuously. **Response:** The drafting team notes that application of fault protective relays for overload

Organization	Yes or No	Question 3 Comment
		protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable <u>fault</u> protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions.
Response: Thank you for your comments, please see the responses provided above.		
Luminant	No	1. Luminant agrees that although Table 1 in Attachment 1 clearly identifies criteria for setting load responsive relays, it is recommended that the drafting team add information in the Attachment that describes the bus voltage conditions as steady state values only and does not consider relay operations for fault conditions. In addition, a statement that the Generation Owner must coordinate relays with applicable AVR response and transmission relaying. **Response:** The drafting team notes the PRC-025-1 is not for the fault or steady state condition, but for the field-forcing condition (short-term). Coordination with AVR response is anticipated to be covered by PRC-019 currently in development and coordination with the transmission system is covered by the existing PRC-001-1 and PRC-027-1 which is also under development. No change made. 2. Luminant recommends the "Pickup Setting Criteria" column for real power output be revised to "100% of maximum seasonal gross or maximum continuous rating of the turbine reported to the Planning Coordinator". **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the

Organization	Yes or No	Question 3 Comment
		maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. 3. In Row 17 (Auxiliary Transformers - Phase Overcurrent Relay), Luminant recommends that the 150% pickup setting criteria be applicable to the relay regardless of its electrical location (high or low side of the UAT). **Response:** The drafting team has revised the unit auxiliary transformer (UAT) Option 17 (now Option 13a and 13b) to reflect that the voltage depends on the winding voltage regardless of location. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Southern Company	No	Fundamentally, requiring entities to relax preferred protection levels on their equipment with no method of (possible) damage cost recuperation due to more liberal protection settings is not fair to the entities that may incur repair/replacement costs. **Response:** The drafting team notes that the entity is expected to provide necessary protection while meeting the requirements of this standard. If legacy approaches do not allow the entity to meet both, other approaches may be necessary. Options have been added to the unit auxiliary transformer (UAT) criteria to allow calculations based on the actual connected auxiliary bus loads and to allow for auxiliary bus performance simulations. For other elements addressed, options have already been provided for the entity to base the protective relay settings on simulated performance. Change made. Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. We believe that Option 17, related to station auxiliary transformers, is unwarranted,

Organization	Yes or No	Question 3 Comment
		excessively liberal in overload allowance, and does not belong in this standard. The station auxiliary power consumption does not directly contribute to the generator overload ability for supporting system disturbance events. Requiring a station auxiliary transformer HSOC (high side overcurrent) relay to be set at the level specified in Option 17 of Table 1 is not justified. We have, for many years, successfully set the station auxiliary transformer HSOC relay pick up value at a much lower value and have experienced very few misoperations. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. The MW value used in the calculation specifics of Table 1 is unclear. We suggest that the MW value used for the calculations be that realized with applying the generator nameplate MVA rating with the rated power factor also found on the generator nameplate. In the draft standard, the MW value to be used is referred to by many different names, including: -Maximum seasonal gross MW reported to the Planning Coordinator -Rated MW -Total nameplate MW -100% of Connected generation reported Establishing the MW value as suggested above removes all confusion to the GO as to which MW value to use, provides a standard method to use, and is close enough to the other values listed to provide the desired generator loading ability. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria.

Organization	Yes or No	Question 3 Comment
		The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. Table 1 is much too complicated. Options 1-4 and Options 13-16 could easily be combined into one set of four options by modifying the Application column. (For example, the combined Options 1 and Option 4 Application column could be labeled “Synchronous Generator or GSU Xfmr - Synchronous Generator”.) Further, Options 1-3 and Options 13-15 should be reduced into one row that specifies the Generator Bus Voltage criteria and the Pickup setting criteria. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The additional methods listed (Options 2, 3, 14, 15) simply confuse the issue. (For example, it is not clear which entity is required to perform a simulation in Options 3, 7, and 15. GO’s generally do not have the system simulation software or the system data required to perform this simulation.) For the rows of Table which remain after this simplification, one calculation example per row would be valuable to demonstrate the intented calculation method. **Response:** The drafting team notes that the standard offers multiple options and that the Generator Owner may perform simulations to determine the expected generator performance during the stressed conditions anticipated by the standard. No change made. We are concerned that the setting limits specific in Table 1 are too liberal to provide adequate overload protection to our generating plant equipment. The required minimum sensitivities for the relaying shown in Table 1 for all units based on a minority (20%) representation of unit capability to provide Q forcing ability results in forcing owners of generators to relax typical relay settings that result in loss of adequate overload protection.

Organization	Yes or No	Question 3 Comment
		Entities should be allowed to protect their equipment from overload rather than be forced to allow a specific amount of overload. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable steady state values. No change made.
Response: Thank you for your comments, please see the responses provided above.		
American Electric Power	No	Generation relay settings typically use the generator bus voltage for calculations. Options 2, 3, 6, 7, 10, 11, 12, 14, 15 and 17 are all expressed as .85 per unit of the transmission system, but should instead be referenced in regards to the generator bus voltage (as Options 1, 4, 5, 8, 9, 13, and 16 are). **Response:** The drafting team notes that the standard requirements are based on the transmission system voltage conditions observed on August 14, 2003. The options that reference the high-side voltage directly reflect this condition. The options that reference the generator bus voltage provide a conservative, but simpler method to approximate the same condition. No change made. Phase distance relays (21) listed in Table 1 should be excluded from any requirements in PRC-023-2- Transmission Relay Loadability. The phase distance relays included in Table 1 can only have settings that will be compliant with one set of requirements not both. Inclusion of these relays in PRC-023-2 and PRC-025-1 would pose a conflict in settings. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection

Organization	Yes or No	Question 3 Comment
		facilities. Change made. Also the out of step relays (78) were listed in PRC-023-2. However, AEP believes that these relays should also be included in Table 1 as a requirement in addition to being an exclusion from PRC-023-2." **Response:** The drafting team notes that out of step tripping of generators will be address in phase three of relay loadability under Project 2010-13.3 – Stable Power Swings and are not within the scope of this project (2010-13.2). Only the generator unit, generator step-up transformer and unit auxiliary transformers are within the scope of the standard. No change made. Seasonal gross Real Power capability" needs to be explicitly defined. **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Tennessee Valley Authority	No	It is not clear if it is required for 1 type (21, 51V, 51C, or 51) to be set according to Table 1 or each type.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. The drafting team further notes that the Generator Owner shall for each load-responsive protective relay that it applies on BES		

Organization	Yes or No	Question 3 Comment
facilities set be set according to the standard.		
Los Angeles Department of Water and Power	No	Options 1, 2, 3, and 4 apply to the relays that are installed on the generator terminals. Options 13, 14, 15, and 16 apply to the relays that are installed on the generator side of the generator step-up transformer. The relay location is electrically the same point as shown in Figure 1 and 2 of the PRC-025-1 document. It is not clear as to the differences to these two sets of Options (1, 2, 3, 4, vs 13, 14, 15, 16). **Response:** The drafting team notes that that referring to the posted standard that Options 1-4 (now Options 1a, 1b, 1c, and 4) apply to each generator unit and Options 13-16 (now Options 7a, 7b, 7c, and 10) apply to the generation step-up (GSU) transformer regardless of the connection point or location of the load-responsive protective relay(s). Each option in Table 1 provide the specific Pickup Setting Criteria (i.e., margins) for the load-responsive protective relay types (i.e., time overcurrent, distance, etc.) in the Relay Type column; for generators (i.e., synchronous or asynchronous) specified in the Application column at a voltage corresponding to the criteria used in the Bus Voltage column. No change made. For each option, provide a one-line diagram example to clarify each scenario. Option 17 is a good example to use as a format. A reference diagram is necessary to add clarity. **Response:** The drafting team has provided example calculations in the Guidelines and Technical Basis to improve the clarity; however, due to the numerous configurations of other options the drafting team has not developed diagrams for the remaining options. Change made.
Response: Thank you for your comments, please see the responses provided above.		
pacificorp	No	PacifiCorp thermal facilities use impedance elements as backup generators, generator bus and GSU protection where the element does not reach through the GSU. This approach results in impedance magnitudes that are significantly lower than those outlined in the Attachment 1 options. It may be beneficial to generator protection engineers if the standard provides registered entities with an option to calculate the impedance reach of the

Organization	Yes or No	Question 3 Comment
		21 element when it is based on the GSU impedance. **Response:** The drafting team notes that while it is unlikely that phase distance settings based solely on the GSU impedance will be a problem for the conditions anticipated by this standard, the GSU impedance is not reflective of these conditions. No change made. Furthermore, while Options 1-4 & 13-16 in Table 1 specify how to determine the generation facility maximum rating and the per-unit bus voltage to perform the impedance reach calculation, these options are missing: (1) the load (or power factor) angles at which the impedance element reach must be evaluated to ensure compliance, and **Response:** The drafting team notes that the power factor angle is determined by the Real and Reactive Power represented in the criteria in Table 1. No change made. (2) recommendations as to how to set load-encroachment element blinders. PacifiCorp recommends that this information be incorporated into the “Guideline and Technical Basis” section of PRC-025-1 to ensure compliance, using Standard PRC-023-2 “Reference Document” as a model. **Response:** The drafting team notes that whether or not load encroachment or blinders are effective requires a case by case analysis. If this approach is used, the entity must determine the generator unit’s ability to operate at all load levels. No change made.
Response: Thank you for your comments, please see the above responses.		
South Carolina Electric and Gas	No	Paragraph 2 of Attachment 1 starting with “Synchronous generator output pickup setting criteria values are determined......” seems to contradict Table 1 regarding the calculation of reactive power output. The paragraph implies that reactive power capability is calculated using the rated power factor however Table 1 implies that it is calculated as a function of rated MW output. **Response:** The drafting team notes that the second paragraph does not reference the

Organization	Yes or No	Question 3 Comment
		power factor as noted in the comment; however, the drafting team has provided examples in the Guidelines and Technical Basis under Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (21) (Options 1a, 1b, and 1c) to improve the clarity. Change made. It would greatly enhance understanding of Table 1 if some examples calculations. This would allow entities to be confident that they were interpreting the wording of the requirements correctly. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: Thank you for your comments, please see the above responses.		
Detroit Edison	No	Please provide setting examples for each type of relay (21, 51V, etc) using both real and reactive power criteria to clarify how Table 1 should be applied. Also, drawings showing location of applicable relays (CT and PT input sources) would be helpful. Reactive power criteria expressed in terms of MW is confusing.
Response: The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.		
Tacoma Power	No	Referring to Attachment 1, Table 1, Options 2, 3, 6, 7, 14 & 15, what current is to be applied through the transformer impedance? **Response:** The drafting team notes the current to be applied through the transformer is the current related to the Real and Reactive Power at the referenced voltage. No change made. The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. Referring to Attachment 1, Table 1, Options 10, 11, 13, 14 & 15, should “Real Power output - 100% of connected generation reported” be changed to something like “Real Power output - 100% of maximum seasonal, aggregate gross MW reported to the Planning Coordinator”? **Response:** The drafting team considered basing the loadability on seasonal output reported

Organization	Yes or No	Question 3 Comment
		to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. Referring to Attachment 1, Table 1, Options 10, 11 & 12, could an exception be granted if the 51 elements are directional toward the generation system? **Response:** The drafting team for Options 10, 11, and 12 (now 8a, 8b, 11a, and 11b) have been augmented to include the phase directional overcurrent (67 function) Relay directional toward the transmission system. See the new Options 9a, 9b, 12 for the phase directional overcurrent (67 function) Relay directional toward the transmission system. The overcurrent element commented above that is directional toward the generation system is now excluded. Change made. Referring to Attachment 1, Table 1, Option 17, should "the element shall be set greater than the calculated current derived from 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating" be changed to something like "the element shall be set greater than 150% of the current derived from the auxiliary transformer nameplate maximum MVA rating"? **Response:** The drafting team has substantially modified Option 13a and 13b formerly Option 17. Change Made
Response: Thank you for your comments, please see the responses provided above.		
MRO NSRF	No	The NSRF agrees with the criteria described in Option 1 through 17 in Table 1, however, we recommend that the Table 1 be broken up into different tables based on the application and relay type. For example, there should be a table for synchronous machines, and one for

Organization	Yes or No	Question 3 Comment
		GSUs, and etc. This would add clarity to Table 1. The addition of the new tables would require that the Application Guidelines section to refer to the new tables be revised.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
ATCO Power	No	There are three issues: (1) on-load tap changers for output transformers are not handled, **Response:** The drafting team notes that on-load tap changers (OLTC) have time delays which prevent them from responding within the timeframe addressed within this standard and, therefore are not included. The drafting team added discussion in the Guidelines and Technical Basis to improve the clarity that the transformer's taps settings, for certain Options, must be considered. Change made. (2) the 150% reactive outflow assumption is not appropriate when using the calculation option as you can calculate the actual VAR outflow for a 0.85 pu voltage depression quite easily from the transformer impedance unless initial conditions with heavy VAR flows are assumed, and **Response: T**he drafting team notes that it has added clarification of the time frame the standard is addressing to the Guidelines and Technical Basis. The timeframe of concern is during field forcing which precludes the calculations described in your above comment. Therefore, it is necessary to use an approximation based on observed data or a simulation as described in the standard. Change made. (3) the initial conditions for the simulation are not specified (full load and unity power factor with all voltages at 1 pu?) and the conditions for simulating the voltage depression are not specified (no swings or close-in faults?) **Response:** The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator

Organization	Yes or No	Question 3 Comment
		Simulation Criteria. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Texas Reliability Entity	No	TRE suggests the following changes for Attachment 1: Relay Settings, Table 1: a) On page 7 under 'PRC-025-1-Attachment 1: Relay Settings' discussion of the synchronous generator reactive capability calculations is confusing. TRE suggests the following language for Paragraph 2: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined based on the unit's nameplate megavoltampere (MVA) and the calculated rated MW at the unit's rated power factor." **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. b) In the Table 1. Relay Loadability Evaluation Criteria; recommend specifying 'Synchronous generator bus terminal' instead of 'Synchronous generators' in the application column for Options 1, 2, 3, 5, 6 & 7. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e.,

Organization	Yes or No	Question 3 Comment
		Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. c) In the Table 1 - Bus Voltage column, clarify that the generator bus voltage calculation needs to include the generator step-up transformer winding tap setting (NLTC or LTC tap settings) in the turns ratio calculation of the generator step-up transformer, when applicable. Suggested language, "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer. The turns ratio calculation of the step-up transformer must include the transformer's NLTC or LTC tap settings implemented in operation." **Response:** The drafting team notes that on-load tap changers (OLTC) have time delays which prevent them from responding within the timeframe addressed within this standard and, therefore are not included. The drafting team added discussion in the Guidelines and Technical Basis to improve the clarity that the transformer's taps settings, for certain Options, must be considered. Change made. d) In the Table 1 - Pickup Setting Criteria column, clarify that the rated power factor must be used to calculate the impedance value. Recommend adding the following note under the setting criteria; "Generator rated power factor shall be used to calculate the impedance value". **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. e) In the Table 1 Option 3- Pickup Setting Criteria column, the Reactive Power output determined by the simulation is typically based on the voltage set point at the controlled bus. This can be a moving target if the simulations are done based on different loading

Organization	Yes or No	Question 3 Comment
		conditions. TRE suggests using the generator reactive capability curve (D-Curve) or the actual reactive test data to determine the generator maximum Mvar capability that is to be used for the impedance calculation. **Response:** The drafting team notes that the generator reactive capability curve (D-Curve) describes steady-state capability, not the generator performance during field forcing conditions. No change made. **Response:** The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator Simulation Criteria. Change made. f) In the Table 1 -The Phase Time Overcurrent Relay (51V) voltage-restrained option does not provide specific voltage restraint slope settings to be used. For consistency purpose, voltage restraint slope settings should be included in the pickup setting criteria. **Response:** The drafting team notes this is a coordination issue that is addressed by the existing PRC-001-1 which is proposed to be replaced by PRC-027-1. No change made. g) TRE recommends including generic D-curve, R-X diagrams, voltage-restrained relay curve, and other overcurrent, voltage controlled relay curves in this standard to provide additional clarification. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Southwest Power Pool Reliability Standards Development Team	No	We would suggest that the table be broken up into different tables based on the application of the relay. For example one table for synchronous machines, one table for GSUs, one table for AUX transformers etc..
Response: The drafting team thanks you for your comment and notes that it has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay		

Organization	Yes or No	Question 3 Comment
type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.		
New York Power Authority	No	Yes for Option 1-16; No for Option 17 as stated in Question 2.
Response: The drafting team thanks you for your comment and has provided a response to New York Power Authority in question 2 above. No change made.		
PPL and Affiliates	No	1. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnection studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #1 above, prepared by the North American Generator Forum (NAGF), comment #3, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #3 below in Question #5. 2. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is also unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition

Organization	Yes or No	Question 3 Comment
		and how hard it is pushed. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #2 above, prepared by the North American Generator Forum (NAGF), comment #4, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #4 below in Question #5. 3. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." The step-by-step calculations wanted can consequently take different paths. Our understanding of what Option 5 requires for example is presented below: -A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. -The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. -The associated MVA at 0.90 PF is 727.778, and the current is 727,778/(18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. -Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT(655^2 + 982.5^2) or 1180.818 MVA. -The current is 1,180,818/(0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals,

Organization	Yes or No	Question 3 Comment
		ref. “Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio” under the “Generator Bus Voltage” column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #3 above, prepared by the North American Generator Forum (NAGF), comment #5, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #5 below in Question #5. 4. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. ***Drafting Team Observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment, #4 above, prepared by the North American Generator Forum (NAGF), comment #11, found in Question #5.* **Response:** Please refer to drafting team’s response to NAGF’s comment #11 below in

Organization	Yes or No	Question 3 Comment
		Question #5. 5. PRC-025 appears to prohibit loadability relays from having multiple definite-time setpoints or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of **comment #5 above, dual ANSI** C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand, however. Nor is it evident why existing protection schemes that are effective and appropriate should be banned. ***Drafting team observation:*** *PPL for its comment, #5 above, has removed the non-substantive phrase "the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding" between "however and Nor…" that is found in the NAGF comment #8 in Question #5. Also, the reference to "comment #5 above, dual ANSI…" the drafting team believe it should be #3 to correspond to PPL's comment in this Question.* **Response:** Please refer to drafting team's response to NAGF's comment #8 below in Question #5. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-

Organization	Yes or No	Question 3 Comment
		generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. 6. We suggest that NERC instead put this proposed standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. ***Drafting team observation:*** *PPL removed from the beginning of the paragraph #6, the first sentence, "GOs are thus being asked to sign a blank check" that is found in the NAGF comment #8 in Question #5 and PPL added the word "proposed" in the first sentence.* **Response:** For comments #5 and #6 above, the drafting team notes that PPL and Affiliates has submitted the same comment prepared by the North American Generator Forum (NAGF), comment #8, found in Question #5 with non-substantive deletions and removals as observed. Please refer to drafting team's response to NAGF's comment #8 below for Question #5.
Response: Thank you for your comments, please see the responses provided above.		
Wisconsin Electric Power Company	No	1. The criteria for Device 21 on synchronous generators could be greatly simplified by using the criteria in IEEE C37.102, i.e. the 21 setting must be less than or equal to the impedance corresponding to 200% of the generator MVA rating at the rated power factor angle, or a modified version of this to accommodate lower system voltages. **Response:** The drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 2. The multiple descriptions under "Bus Voltage" (see options 1-3, 5-7, etc) cause this criteria to be difficult to understand and to apply. It is not readily apparent what the

Organization	Yes or No	Question 3 Comment
		different Bus Voltage options are attempting to accomplish. Are options 1 and 2 identical except for the voltage magnitude? It is not clear why a voltage of 0.95 pu is referenced in Option 1 when the Guidelines and Technical Basis section states that the criteria in Table 1 is based on 0.85 pu transmission voltage. **Response:** The drafting team notes that both the 0.95 and 0.85 per unit Options are fundamentally based on a system voltage during a disturbance of 0.85 per unit, and represent two different complexities for the resulting calculations for distance relays which are connected to generator bus voltages. Options 1, 5, and 13 (now 1a, 2a, and 7a) present the simplest of available calculations by assuming a 10% voltage drop through the GSU transformer (hence a 0.95 per-unit generator bus voltage), and simply adjusting the system voltage by the GSU turns ratio. Options 2, 6, and 14 (now 1b, 2b, and 7b) provide a more involved, but more precise calculation by establishing the system voltage at 0.85 per unit and evaluating the actual voltage drop through the GSU transformer and representing the actual GSU turns ratio and impedance. Also, the terms “transformer turns ratio and impedance” are not clear as to the intent, and perhaps should be deleted. **Response:** The drafting team notes that many GSUs are operated at off-nominal taps in order to achieve optimal generator performance, the standard specifies that the actual turns ratio of the GSU be used. For example, a GSU connecting an 18 kV generator to a 345 kV system may be actually tapped at 362 kV – 17.1 kV. The GSU impedance is used for the calculation of voltage drop through the GSU. No change made. In the references to “simulation” in options 3, 7, and 15, what specific types of analytical studies are intended here, and what specific generator models are required for them? For these reasons, an approach that is simpler to apply is needed for Table 1. **Response:** The drafting team notes that simulations must represent dynamic performance, and must use a comprehensive generator model that includes accurate excitation system

Organization	Yes or No	Question 3 Comment
		performance. The criterion for the simulations themselves, once an appropriate simulation tool is selected and model developed, is fairly simple, and will be further described within the Guidance and Technical Basis section. A generator output of the maximum gross real power capability at normal system voltage should be used as the initial condition, and system voltage subsequently reduced to 0.85 per unit. The generator performance (within the simulation) is then observed to determine the maximum value of reactive power output. For entities that prefer to use alternate and simpler criteria, Options 1a, 2a, or 7a may be used. No change made. 3. There is a need for a good detailed example calculation for the various options in Table 1. **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 4. It may be better to break up Table 1 into separate Tables for Generator, GSU's, and Auxiliary Transformers. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made. 5. In Attachment 1, 2nd paragraph: a. Replace "Synchronous generator output pickup setting criteria values" with "Synchronous generator relay setting criteria values" **Response:** The drafting team notes that the criteria only addresses portions of the overall relay setting criteria for synchronous generators. However "output" has been replaced by "relay" in consideration of your comment. No change made. b. We suggest that the setting criteria be based simply on the generator MVA capability and

Organization	Yes or No	Question 3 Comment
		rated power factor, instead of calculating it using the real power rating in MW. **Response:** The drafting team notes that the rated power factor as suggested does not reflect the performance of the generator during field forcing conditions and is therefore not applicable. Please see the Guidelines and Technical Basis for more information. No change made. 6. Some of the terms may be misunderstood and should be clarified. "Generator Bus" is at the terminals of the generator. Suggest using a term such as "System Bus" or "Transmission Bus" or similar to designate the bus to which the GSU transformer high-side terminals are connected to. **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made.
Response: Thank you for your comments, please see the responses provided above.		
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
Operational Compliance	Yes	
Ingleside Cogeneration LP	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	
ReliabiltiyFirst	Yes	

4. **Do you agree an Implementation Plan of 48-months to install load-responsive protective relay settings is achievable? If not, provide an alternative with specific rationale for such an alternative period.**

Summary Consideration:

Approximately 22 commenters supported by at least 71 different people that provided comments for question #4. There were only two common comment themes presented in question #4. The implementation period was the majority theme.

The first majority comment theme resulted in a change to the standard.

(1) Only four comments supported by individual entities agreed that a 48-months implementation plan was sufficient time to install settings on load-responsive protective relays. One comment expressed a general dissatisfaction with the implementation period. Resoundingly, more than 15 comments supported by at least 40 entities suggested a 60-month implementation plan or greater. Five comments suggested an 84-month implementation, one comment suggested a 120-month implementation, and two comments recommended a phased approached like other reliability standards. The drafting team considered the varying degree of time periods and approaches; and concluded the most reasonable approach is a two-part implementation plan.

For those load-responsive protective relays determined to <u>need only a setting change, entities</u> must have the setting applied by the end of the 48-month implementation period; and for those load-responsive protective relays determined to <u>require replacement</u> to achieve the reliability goals of the standard, entities must have replacements made and settings applied by the end of the 72-month implementation period. For load-responsive protective relays that become applicable due to an outside event (i.e., regulatory action), entities will have a 48-month implementation period only.

There was one minority comment theme in this question.

(2) A single comment supported by at least eight entities was concerned about the potential overlap between the mandatory PRC-023-2 – Transmission Relay Loadability standard and the draft PRC-025-1. The drafting team had also previously identified this issue prior to initial posting, but did not want to delay posting while considering a solution. To resolve this issue, the drafting team has obtained approval to post a supplemental Standard Authorization Request (SAR) from the Standards Committee on January 16, 2013 to modify PRC-023-2 to establish a bright line between the mandatory PRC-023-2 for transmission relay loadability and the future PRC-025-1 standard for generator relay loadability. This supplemental SAR and proposed changes to PRC-023-2 are posted concurrently with draft 2 of PRC-025-1. Comments may be provided using the SAR comment submittal form. Additionally, the drafting team modified the Applicability section of the standard to coincide with the proposed changes to PRC-023-2.

Organization	Yes or No	Question 4 Comment
ACES Power Marketing Standards Collaborators	No	(1) The implementation plan is unreasonable in the amount of time needed to have generation units comply with the standard, especially with the considerations of having to replace existing protective relays, meeting budgetary concerns, coordination with other entities, the time for procurement, and planning outages to complete the necessary work. We suggest 60 months. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made. (2) As mentioned above, there are overlaps with this standard and the applicability section and implementation plan for PRC-023-2. If a generator was subject to PRC-023-2 as a result of being designated by its Planning Coordinator, it would have the "later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date." The drafting team needs to review the applicable time frames, modify PRC-023-2 and provide a clear and understandable timeline that does not have conflicting standards interfering with its implementation. **Response:** The drafting team notes that PRC-023-2 became mandatory as of July 1, 2012, that the implementation of PRC-023-2 is specifically designed for transmission relay requirements, and it is not within the drafting team's scope of work. The drafting team has framed the implementation period of PRC-025-1 with regard to Generator Owners and the circumstances applicable to operating generation. No change made. (3) We strongly suggest that the drafting team review PRC-023-2's implementation plan for

Organization	Yes or No	Question 4 Comment
		GO/GOPs and modify both standards to avoid overlap, confusion, and as discussed above, double jeopardy. **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made.
Response: Thank you for your support and comments, please see the responses provided above.		
American Electric Power	No	Due to the expanded scope of this project and the resulting (proposed) requirements, a significant amount of research and studies may need to be performed in order to properly inventory the existing relays and determine their settings. This is not an automated process, and would require extensive print reviews and field verification. The proposed implementation plan emphasizes the time needed to change the relay settings, but deemphasizes the time and effort required to inventory the relays, determine their current settings, and perform the calculations required to determine the new settings. For entities with a large generating fleet, this phase alone could take four years or more to accomplish. Again, this would include the time and resources necessary to actually make those setting changes in the field. Rather than requiring that all research and implementation be completed within 48 months, a time period much too short to perform the work necessary to meet the requirement, AEP believes this standard should instead utilize the precedent of a phased-in approach over 10 years (for example, 50% complete in 4 years, 75% in 7 years and 100% in 10 years).In addition, the work required for this project requires a specific expertise held by a limited number of subject matter experts, and who are also needed to implement other NERC standards and support ongoing reliability efforts. This further supports the need to extend the time allotted beyond four years.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be		

Organization	Yes or No	Question 4 Comment
completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Indiana Municipal Power Agency	No	IMPA recommends using a phased-in Implementation Plan. Generator Owners will have to review current settings and based on this analysis they may have to replace some relays and/or coordinate these relay settings with their Transmission Owner. If relay replacement is required, Generator Owners will have to budget for the new relays. If settings need to be changed, the Generator Owner(s) will need to verify relay settings with the Generator Manufacturer to ensure there are no warranty/safety concerns associated with the relay setting changes. IMPA recommends a 50% completion in 48 months and a 100% completion in 72 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Duke Energy	No	Implementation should be aligned with other similar standards, such as PRC-024, or even extended based on the number of simulations and relay replacements that will be required.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Northeast Power Coordinating Council	No	In the case where existing protective relay replacement may be necessary, 48 months does not provide adequate time to budget, design, coordinate, procure materials, and schedule the work that would have to be done during outage of sufficient duration. Suggest

Organization	Yes or No	Question 4 Comment
		extending the Implementation Plan duration to 60 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Dominion	No	In the case where existing protective relay replacement may be necessary, Dominion does not feel that 48 months provides adequate time to budget, design, coordinate, procure materials, and schedule the work in an outage of sufficient duration. Dominion suggests that 60 months may be more appropriate in this instance.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Ameren	No	Please allow 60 months to implement if indeed protection system equipment or schemes must be changed to comply with R1. More than 48 months will regularly be needed to budget, design, procure materials, obtain construction outages, install and commission such protection system equipment changes.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Tennessee Valley	No	Recommend a schedule that will coincide with the protective relay requirements stated in

Organization	Yes or No	Question 4 Comment
Authority		the revised NERC, PRC-005-2, Protection System Maintenance standard. The protective relays requirements within PRC-025-1 should coincide with PRC-005 in order to maximize benefit of maintenance to satisfy these two standards and to minimize resources necessary to perform the relay settings calculations and installations required by PRC-025-1, if the relay settings need to be revised from current PRC-005 settings. Recommend both implementation plans should be a minimum of 72 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Ingleside Cogeneration LP	No	Similar to PRC-024-1, ICLP believes there needs to be an allowance for those equipment types which cannot accommodate the Table 1 settings. In particular, the variation in the ancillary systems which support the generator is significant - and 48 months will not be sufficient to address every situation.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Detroit Edison	No	Suggest that allowing 72 months to become 100% compliant would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of		

Organization	Yes or No	Question 4 Comment
the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
South Carolina Electric and Gas	No	The 48 month time period may not allow enough time to engineer and then schedule the work necessary to implement the changes. The work required to implement new relaying schemes may be intensive if new relays need to be installed. This type of work requires extended outages that may not occur on an annual or even bi-annual basis. The implementation plan should be modified to at least 60 months.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Southern Company	No	The implementation plan for execution of Requirement R1, as written, is too short. This requirement will cause GOs to have to check calculations for every relay in the scope of Table 1 for all of its facilities. Checking the setting limits agains the equipment safety levels will take significant time. Equipment procurement, where necessary, and unit outage availability will dictate the exact time required to address the scope of the applicability. It is recommended that the implementation time be increased to 7 years.
Response: The drafting team thanks you for your comment and recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Texas Reliability Entity	No	TRE thinks that the implementation plan is too long and we suggest 24 months.

Organization	Yes or No	Question 4 Comment
Response: The drafting team believes in consideration of generator refueling, outage planning, analysis, maintenance cycles, budgeting, and potential protective equipment replacement that the 24 months as proposed is not adequate to allow entities time to become compliant with the standard. No change made.		
PPL and Affiliates	No	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC-registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. ***Drafting team observation:*** *The drafting team notes that PPL and Affiliates has submitted the same comment prepared by the North American Generator Forum (NAGF), comment #1, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #1 below in Question #5. 2. It is additionally not unusual for baseloaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future **due to changing economic conditions**. ***Drafting team observation:*** *The drafting team notes that PPL and Affiliates has submitted a modification to the comment prepared by the North American Generator Forum (NAGF), comment #1, found in Question #5.* **Response:** Please refer to drafting team's response to NAGF's comment #1 below in Question #5.
Response: Thank you for your support and comments, please see the responses provided above.		

Organization	Yes or No	Question 4 Comment
Wisconsin Electric Power Company	No	48 months may be achievable for utility generation, but perhaps not for merchant plans. A timeframe of 72 months is suggested. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.
Response: Thank you for your comments, please see the responses provided above.		
Manitoba Hydro	Yes	Although we agree with the implementation plan, the Applicable Entities should match the language in the standard i.e. Generator Owners 'that applies....' The language in the Implementation Plan section is awkward in that they refer to 'protective relays applicable to this standard' when it would seem to make more sense to refer to 'protective relays to which this standard applies'.
Response: The drafting team thanks you for your support and comment and has added a note to direct the reader to the standard for further information. The implementation plan is only intended to list the applicable entities as a reference and that the standard is the governing document for the full Applicability for function entities and Facilities. Change made.		
Los Angeles Department of Water and Power	Yes	LADWP agrees the Implementation Plan to install load-responsive protective relay settings is achievable in 48 months.
Response: The drafting team thanks you for your support and comment.		
ATCO Power	Yes	NOT APPLICABLE IN MY JURISDICTION
Response: The drafting team thanks you for your support and comment.		

Organization	Yes or No	Question 4 Comment
Operational Compliance	Yes	We agree with the Implementation Plan of 48 months, but might like to see this time period broken into smaller phases.
Response: The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made.		
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc. & Affiliates	Yes	
MRO NSRF	Yes	
Luminant	Yes	
Southwest Power Pool Regional Entity	Yes	
Salt River Project	Yes	
pacificorp	Yes	
Tacoma Power	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 4 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
ReliabiltiyFirst	Yes	

5. **Do you have any other comments? If so, please provide suggested changes and rationale.**

Summary Consideration:

Approximately 19 commenters representing about 37 entities provided general comments for question #5 many of which were raised in the previous four questions. There were at least 24 varying themes supported by nine or fewer entities all of which were minority issues with regard to question 5. Some comments raised in the previous four questions above may have been majority comments for one of these other questions; therefore, the drafting team encourages the reader to review those summaries and responses as well.

Two-thirds of the 25 varying minority themes did not result in changes to the standard. All of these comments were addressed in the previous four questions by the drafting team. One-third of the 24 varying minority themes resulted in changes of varying levels to the standard. Those changes include the following seven items. (1) The drafting team did not post the VSLs in the draft 1 posting, but have provided them for the draft 2 posting. One commenter suggested the VSL should be based on MWh as a method to gradate the VSL; however, the drafting team did not see this as a suitable approach. (2) There were concerns about the Applicability section of the standard. The drafting team made changes to more clearly identify the BES Facilities and the equipment that is included and that the standard applies to load-responsive protective relays. (3) The drafting team received numerous suggestions in the previous questions above to clarify the Attachment 1, Table 1. The drafting team restructured Table 1 for clarity. (4) One comment suggested using "apply" rather than "install" in Requirement R1. The drafting team agreed and made the change based on other comments above. (5) One commenter provided suggestions to revise the Purpose statement. The drafting team agreed to most of the suggestion and made clarifying edits as to the purpose of the standard. (6) A single commenter suggested adding examples to the Guidelines and Technical Basis. The drafting team added additional Guidelines and Technical Basis text and examples based on other comments above.

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Manitoba Hydro	(1) Regarding "Applicability", it is not clear what type of auxiliary transformers should be included as the "Applicable Facilities". For example, if the auxiliary transformer is NOT the only supply to the generator, does the standard still apply to this auxiliary transformer? **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends

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	that the related load-responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. (2) On page 7 of 22, the following sentence is unclear: "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability, in megawatts (MW), as reported to the Planning Coordinator; and the unit's Reactive Power capability, in Megavoltampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor". Manitoba Hydro suggests rewording this sentence for clarification. Additionally, should "rated MW" be changed to "rated MVAR'? **Response:** The drafting team considered basing the loadability on seasonal output reported to the Planning Coordinator or Transmission Planner. The standard now reflects the maximum output reported (regardless multiple seasonal capabilities) to the Planning Coordinator or Transmission Planner for the Real Power component and the nameplate rating of the generator for the Reactive Power component being used when determining the settings for the load-responsive protective relays because prime movers have too many variables (i.e., equipment issues, environmental factors, etc.) controlling output rating. The generator unit ability is fixed based on its nameplate rating and is standard throughout the industry. Change made. (3) On page 3, A Introduction, Purpose: We find the purpose quite poorly worded as it stands. It is written in absolutes (i.e. generators do not trip, disturbances that are not damaging) which is quite different than the wording used in the Background to describe the standards (i.e. that did not apparently pose a direct risk). It would seem more appropriate to use language that discusses the purpose as opposed to the outcome. For example, language similar to "To set load responsive generator protective relays at a level designed to prevent tripping of generators during system disturbances that do not apparently pose a direct risk to the generator in order to prevent the unnecessary removal of the generator from service.' **Response:** The drafting team applied most of the suggestion to the purposed statement; however, the use of "apparently" is more correct as used in the Background section because it refers to conclusions drawn from the analysis of major disturbances. Change made.

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	(4) On page 3, A Introduction, Applicability, 3.1.1: The standard uses the term Generator Owner in terms of functional entities. However, the definition of Generator Owner only makes reference to owner of generating units. Does that still work with 3.2.2 and 3.2.3 which includes Elements other than generating units? **Response:** The drafting team notes that the Functional Model definition for "Generator Owner" is an entity that owns generating units. However, the Applicability section identifies the condition for applicability for a Generator Owner and then identifies the "Facilities" to which the Generator Owner must comply with the standard for the items that apply load-responsive protective relays. No change made. (5) On page 3, A Introduction, Background: Does this 'Background' section become part of the standard once finalized? **Response:** The drafting team notes that the numbered sections within the standard remain upon industry approval. No change made. (6) Attachment A: The opening line should refer to each Generator Owner that applies load-responsive protective relays on the Facilities listed in 3.2 in order to be consistent with the applicability section of the standard itself. **Response:** The drafting team has added the additional reference text for clarification. Change made. (7) Revisions or Retirements to Already Approved Standards: There is a reference to Order NO. 733, paragraph 102. We believe that this needs some elaboration because we are not sure that paragraph sets out the requirement that is in the standard. **Response:** The drafting team apologizes for this error and notes the correct paragraph (i.e., 108) is provided in the summary consideration above. No change made.
Response: Thank you for your support and comments, please see the responses provided above.	
ACES Power Marketing Standards Collaborators	(1) We have concerns with the drafting team's approach of requiring replacement of legacy relays for the sake of complying with its proposed standard. This additional strain on resources will have an adverse impact for smaller entities. Smaller entities do not have unlimited budgets and it is

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	difficult to justify the replacement of working equipment just to comply with a regulation. The regulators need to consider reevaluating the threshold that is needed to comply with this standard. If a protection relay is not broken, there should not be a reason to replace it. There is not sufficient justification that having a modern advanced-technology relay with extra functionalities to have a reliability benefit that is commensurate with the cost. **Response:** The drafting team has developed the standard in accordance with the regulatory directives concerning generator relay loadability. The directives are an outcome of the 2003 blackout report and revealed the need to improve generator relay loadability. The goal of the standard is to provide a conservative margin based on generation unit output for which each Generator Owner shall set its load-responsive protective relays. No change made. The drafting team notes that per the 'Power Plant and Transmission System Coordination' – July 2010 – The total number of generators that tripped in the 2003 blackout is 290; eight of those by phase distance and 20 more by 51V protection. Additionally, the cause of tripping for 96 generators is unknown, either because the generator failed to respond to data requests or because the Generator Owner was not able to determine the cause. No change made. (2) We suggest the drafting team complete the VSL table and provide a draft RSAW of this standard. PRC-023-2 is currently in effect and there is no guidance or RSAW posted, which results in a tremendous amount of confusion on how to comply with the standard. We strongly suggest that the SDT plan for how the industry will need to comply with PRC-025-1 and provide a sample RSAW. Also, if this standard is results-based, then is it possible to consider internal controls for the responsible entity to correct relay settings without consequences of self reporting? **Response:** The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website. The drafting team notes that the standard PRC-023-2 RSAW (11/15/2012) is currently posted on the NERC website under the Compliance tab. The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps

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	in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change **made.** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. (3) We disagree with the setting of a high VRF for Requirement R1. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with the NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. A Medium VRF is more appropriate. **Response:** The drafting team notes that the circumstances around the August 14, 2003 blackout were exacerbated by the loss of generation. Applying a Violation Risk Factor (VRF) of Medium would be inconsistent with the NERC definition. Failure to apply the settings could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition; therefore, a VRF of High has been selected. This VRF is also consistent with the approved version of PRC-023-2 - Transmission Relay Loadability standard. No change made. (4) We disagree with the statement "that it may be necessary to replace the legacy relay with a modern advanced-technology" on page 14 in the Guidelines and Technical Basis section. Section 215(i)(2) is very clear that the ERO or Commission are not authorized to order construction. Thus, a standard cannot compel relay replacement. **Response:** The drafting team notes that Section 215 (i)(2) of the Federal Power Act states: "This section does not authorize the ERO or the Commission to order the construction of

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	additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." This clause pertains to the construction of additional generation or transmission capacity and not the modification, replacement, or installation of a relay that may be necessary to meet the reliability goal of a standard. No change made. (5) There is text in the comment form regarding using a Method 1 or Method 2 for relay loadability. We can find no mention of these methods in the standard or Guidelines and Technical Basis. The methods actually require calculating loadability at two operating points. While one of the points appears to be Pick-up Setting Criteria in Table 1 of Attachment 1, the other is not referenced anywhere in the standard. Please include this section in the standard as appropriate or remove it from the comment form as its purpose is very confusing. **Response:** The drafting team believes that you may be looking at a superseded draft version of the standard. The drafting team believes that the bus voltage nomenclature in the standard is clear. No change made. (6) Thank you for the opportunity to comment.
Response: Thank you for your comments, please see the responses provided above.	
Essential Power, LLC	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, "while maintaining reliable protection," aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot

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	could be cast. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from year to year depending on equipment condition and how hard it is pushed. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "...a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set

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	under the TO’s direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. “Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio” under the “Generator Bus Voltage” column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term overheating considerations (“field forcing is limited by the field winding thermal withstand capability”) may not be correct, however. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core

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	clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory." Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. 8. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). Such an approach to loadability settings would degrade

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	rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "...while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action. 9. The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." It should be replaced by the term "generator bus or high side-to-medium voltage," as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated

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	any economic rationale for having black-start facilities. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. 13. Using the term “apply settings” rather than “install settings” in Requirement R1 better suits the accepted terminology for setting the protective device parameters. 14. The phrase “while maintaining reliable protection” in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with “achieving ...desired protection goals”. In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity’s existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection

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	used by many companies has proven (over multiple decades) to be adequate for protecting equipment and providing reliable power supply to customers.
Response: The drafting team thanks you for your comments and notes that Essential Power, LLC has submitted the same comments prepared by the North American Generator Forum (NAGF). Please see the responses to these comments below in the response to the North American Generator Forum comments for Question #5.	
Tennessee Valley Authority	1. There is a strong relationship between this reliability standard, PRC-025-1, Generator Relay Loadability, and PRC-005-2, Protection System Maintenance, regarding the testing, maintenance, and installing the settings on the same protective system relays. To ensure PRC-025 and PRC-005 are in sync with each other, recommend each be referenced in the "F. Associated Documents" of the other. **Response:** The drafting team does not believe referencing another standard in Section "F" achieves more clarity or provides additional benefit to the standard; however, the documents already named in the standard will be added here as they are relative to the standard. Change made. 2. Recommend PRC-025-1 relay settings be recalculated at a frequency that coincides with PRC-005-2, Protection System Maintenance, performance frequencies found in the PRC-005-2, respective tables. The standard should also allow the generator owner to determine for their own applications whether the on-going repetitive calibrations and functional testing should be time based, performance based, or a combination of the two, in accordance with PRC-005-2. **Response:** The drafting team understands the logic suggested here. Each standard must stand on its own. The standard does not preclude the Generator Owner from creating its own internal control over PRC-025-1 based on PRC-005-2 activities; however, the drafting team has modified the implementation plan to which should allow the Generator Owner to align its activities. Once the relays are set, there is no reason to perform on-going repetitive calibrations and functional testing as a part of PRC-025-1. Change made to the implementation plan.
Response: Thank you for your comments, please see the responses provided above.	

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American Electric Power	Are transformers which are independent of the generator bus, and are fed from the grid, in scope? Figure 1 seems to infer the inclusion of such devices, but if so, that is not made explicit within the description provided in 3.2.3 and Note 1. Both 3.2.3 and Note 1 need to be more specific or refer to an attachment for examples. **Response:** The drafting team refers to the footnote in the Applicability (footnote 1). The connection is not relevant. Also, the drafting team provided in the posted draft 1 standard, figures that illustrate this condition. No change made. This standard does not explicitly state which auxiliary transformers are in scope. AEP recommends clearly identifying whether the standard is applicable to Reserve Auxiliary Transformers. In addition, Footnote 1's second sentence should be modified to state "Loss of these transformers will result in the generator's immediate removal from service."The scope of this draft is inconsistent with the title and purpose with respect to generator protective relays as opposed to generation relays. The phrase "generator relay" has a specific meaning to a relay engineer, and encompasses only a subset of the generation relays covered under this standard. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Idaho Power Company	Based on the language of Section 3.2.3, which describes the applicable facilities, we believe some addtional clarification should be added to Footnote 1. Many modern static excitation systems have a sizable dedicated transformer. We believe a mention of these excitation transformers would provide needed clarification.
Response: The drafting team notes that the concerns raised relative to relays on an Exciter PPT and ISO Phase Bus between the	

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generator and the unit auxiliary transformer (UAT) are not within the scope of the project. Only the generator unit, generator step-up (GSU) transformer, unit auxiliary transformers (UAT), and lines are within the scope of the standard. No change made.	
Los Angeles Department of Water and Power	For the Transmission Relay Loadabiltiy Program, examples and job aids were provided to establish a uniform method to calculate relay settings. Examples and job aids should also be included for Generator Relay Loadability.
Response: The drafting team thanks you for your comment and has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.	
ATCO Power	Get rid of the 150% assumption. It can be calculated directly from transformer impedance. Get rid of the special cases -- there are too many, such as load tap changers, that you are not handling. Simply require that generators' 21 relays be set to ride through the consequences of a 0.85% transmission voltage depression with 115% fudge factor, and specify the loading range you care about for special cases. This works out to a mho circle, diameter=Xt/(0.15 * 1.15), MTA=90 degrees, zero offset. Compliance verification is a straightforward engineering exercise.
Response: Thank you for your comments, the drafting team has added clarification of the timeframe the standard is addressing to the Guidelines and Technical Basis. The timeframe of concern is during field forcing which precludes the calculations described in your above comment. Therefore, it is necessary to use an approximation based on observed data or a simulation as described in the standard. The drafting team added the special cases (Options) to allow the entity to use the simplest calculation to the more involved and precise calculations or simulation. The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.	
Ingleside Cogeneration LP	ICLP believes that NERC's Compliance organization should be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the

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	standards for exactly this reason.
Response: The drafting team believes that draft PRC-025-1 RSAW will lessen concerns about the compliance test an auditor would use. Please see the posted draft RSAW under the Compliance section of the NERC website.	
Tacoma Power	Referring to the first paragraph of Attachment 1, Options 1-17 are not truly exclusive options. Options 1-3, Options 5-7, Options 10 & 11, and Options 13-15 each appear to be exclusive options. However, an entity may, for example, need to apply Options 1, 2 or 3 together with Options 10 or 11 together with Option 17. Consider separating Table 1 into multiple tables, each table based upon a different combination of relay type and application. Each option within each table would then be exclusive.
Response: The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.	
Southwest Power Pool Regional Entity	Since this standard isn't enforceable until 48 months after approval, why not make the effective date 48 months after approval? This would reduce confusion concerning Registered Entities' requirements for performance (such as outage scheduling and early adoption) during the 48 month implementation period.
Response: The drafting team thanks you for your comment and notes that the standard's effective date begins with an implementation plan based on the effective date. Using this structure places the standard in effect and requires the Generator Owner to apply the required settings based on the implementation plan period. No change made.	
Independent Electricity System Operator	The proposed effective date in the implementation plan may not clearly address a potential conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that the sentence be re-arranged as follows: [First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory

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	approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees.]
Response: The drafting team thanks you for your comment and notes that the effective date language has been vetted by NERC Legal staff and provided as standard language for reliability standards. The current language is clear in the first sentence that for United States entities, the Federal Energy Regulatory Commission or FERC (i.e., "applicable regulatory authorities") and for Canadian entities (or others) the first sentence means its applicable regulatory authority. The second clause is for those entities (registered with NERC) which are not governed by a regulatory body, the standard becomes effective upon NERC Board of Trustees approval. The order of the clauses does not affect the applicability. Since moving the third clause up in order does not change its applicability, no changes were made. For a better understanding of the suggestion, the drafting team has formatted the suggestion from above with respect to the approved template language provided in reliability standards. For reference only: **Reference**: First day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees. ~~or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~	
pacificorp	The use of the term "Bulk Electric System generation Facilities" in the Applicability Section 3.2 of the standard is not explicitly defined. PacifiCorp recommends that the Standards Drafting Team include generator size to further refine the applicability of facilities under this standard.
Response: The drafting team thanks you for your comment and notes that the use of Bulk Electric System defines what Facilities are applicable to the standard. The team has utilized this definition because it is a NERC defined term and is also undergoing improvements and exclusions. The NERC registration criteria define the minimum sizes that require an entity to register as a Generation Owner. Also, this standard does not provide any exclusion based on physical factors (i.e., size or voltage connection) on the basis of information which demonstrated that generators of all sizes, when connected, play a role in maintaining reliability during Transmission system disturbances; therefore, the team believes that defining the applicability provides no additional reliability benefit. No change made.	

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Nebraska Public Power District	We have seen many interpretations of the calculations for Table 1 during industry forums. Examples need to be provided.
Response: The drafting team thanks you for your comment and has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made.	
Ameren	Yes. (1) Applicability should be consistent with PRC-023-2 (generators connected at 200kV and above, etc.). **Response:** The drafting team notes that the use of Bulk Electric System defines what Facilities are applicable to the standard. The team has utilized this definition because it is a NERC defined term and is also undergoing improvements and exclusions. The NERC registration criteria define the minimum sizes that require an entity to register as a Generation Owner. Also, this standard does not provide any exclusion based on physical factors (i.e., size or voltage connection) on the basis of information which demonstrated that generators of all sizes, when connected, play a role in maintaining reliability during Transmission system disturbances; therefore, the team believes that defining the applicability provides no additional reliability benefit. No change made. (2) System connected auxiliary transformers should be excluded. This is consistent with the industry's determination in PRC-005-2, which has now passed recirculation ballot. **Response:** The drafting team is addressing regulatory directives by including generator step-up (GSU) transformer and unit auxiliary transformers. Also, the team notes that load-responsive protective relays function based on changing system conditions, such as, a depressed voltage. This condition can cause generator step-up (GSU) transformers to unnecessarily trip as well as unit auxiliary transformers (UAT) which supply power to the generator unit when running. Additional options based on comments have been provided to address UAT short-term loading anticipated by the standard. Change made. (3) VSLs are listed as 'to be determined'. We recommend that severity be risk-based by relating it to the % of MWh the generator in violation has provided during the period of violation (i.e. % of GO

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	entity’s total MWh production.) **Response:** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. The drafting team also notes that a VSL cannot be based on availability. If a generator is online, it is expected under the premise of the standard to remain connected during the conditions discussed in the standard. The VSLs are based on a per violation per day basis for not complying with the standard. The drafting team has constructed the VSLs consistent with the NERC VSL Guidelines. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Southern Company	Yes. In Applicability Section 3.2, we disagree with the specifier “including those identified as Blackstart Resources in the TOP’s system restoration plan”. The additional small units this may draw in to the scope of this standard are not large enough to be significant contributors to correcting frequency and voltage perturbations on the transmission network. **Response:** The drafting team believes that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator’s system restoration plan (i.e., SRP), if identified as being BES. No change made. The word “overall” does not add any value to applicability section 3.2.3. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying “running power” to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these

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	transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. If the voltage restrained overcurrent relay is the primary relay of concern (as noted from the 14 Aug 2003 disturbance), perhaps the solution is to require that they are replaced with alternative types of relaying rather than by specifying the desensitizing setting specifications. **Response:** The drafting team notes that a number of load-responsive protective relays operated during the August 14, 2003 blackout that were contributory to the expanse and spread of the outage. The regulatory directive from Order No. 733 that the team is addressing identifies load-responsive phase protection relays as the protective function concerning loadability. No change made. We have real, historical cases where a generator back-up overcurrent relays set at 115 to 130% of the unit rating have saved the units that were exposed to either a low-level, close transmission faults or excitation system malfunctions. A possible solution to generator relaying modifications to provide the maximum allowable loadability for supporting system disturbance events may be to remove all voltage restrained/controlled overcurrent relays and replace them with a standard 51 function. This relay could be set just under the generator ANSI overload curve to protect the unit from low level overload. This would give plenty of area for swings while still protecting the generator. The 21 function could then be adjusted to pickup at 180 to 200% of the units MVA rating with appropriate time delay to coordinate with transmission Zone 3 relays. An alternative solution to specifying the generator relay settings is to allow the PRC-001 standard (currently under draft) to take care of the desired coordination between generator relaying and transmission system relaying. In that standard, the GO and TO must confer with one another regarding the coordination of the generator relaying and the transmission system relaying. The loadability issue of generators, we believe, can be adequately resolved by the coordination requirements to be contained in PRC-001. **Response:** The drafting team notes similarly to the loadability requirements imposed on

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	Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall, and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.	
North American Generator Forum (NAGF)	1. The 48-month period in the implementation plan for 100% compliance should be increased to at least 84 months in light of the, “while maintaining reliable protection,” aspect of R1. That is, one cannot just calculate settings per Att. 1, purchase new relays where necessary, and then schedule implementation for the next planned outage. It is first necessary to perform an engineering study for every NERC registered unit in the fleet to determine if (discussed in greater detail below) and how the settings criteria in Att. 1 can be accommodated without potentially leaving major equipment susceptible to damage. This will take substantial time. Additionally, it is not unusual for base loaded fossil units in a deregulated market to go five years between major outages, depending on unit size, type and duty. This figure may increase in the future, as declining power prices may cause once-base loaded units to sink into a semi-peaking mode of operation. **Response:** The drafting team recognizes that 48 months is too short for overall implementation of the standard and has instead proposed a two phase implementation approach. The first phase establishes that setting calculations be completed and required settings be applied to existing

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	protective relays in 48 months; unless, equipment replacement is necessary, then such replacements must be completed within 72 months. The drafting team firmly believes that duration in excess of 72 months would be excessive. Change made. 2. The currently "To be determined" VSLs would need to be defined before an affirmative ballot could be cast. **Response:** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made. 3. The statement at the top of Att.1 that, for synchronous generators, "Reactive Power capability, in megavolt ampere-reactive (Mvar), is determined by calculating the rated MW based on the unit's nameplate megavolt ampere (MVA) at rated power factor," is not correct. A rating is a max-allowed value per OEM specifications, Planning Coordinator interconnect studies and the like, while a capability is what a unit is actually able to do. The rated (or nameplate) reactive power of the generator as a component is determined as stated in Att. 1, but the MVAR capability of the generation unit is determined via test and is usually restricted by aux bus voltage limits to a value considerably less than the generator D-curve rating. If PRC-025 is meant to refer only to generator ratings and not to unit capabilities an explanation to this effect should be included, and the terminology should be made consistent. **Response:** The drafting team notes that the Mvar capability in the standard is not directly obtained from the steady state capability curve. The Mvar capability is a function of the field forcing capability of the exciter/field during a system disturbance. This Mvar value is determined by calculating the rated MW based on the unit's nameplate megavoltampere (MVA) at rated power factor. Simulations and actual disturbances show that the value of the maximum Mvar is approximately equal to 150% of the derived nameplate MW value. Refer to Guidelines and Technical Basis within the standard for more information on field forcing. No change made. 4. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the real power output is, "100% of maximum seasonal gross MW reported to the Planning Coordinator," is unclear. We declare and seasonally verify an installed net power capacity, and the gross power generated during these tests varies from

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	year to year depending on equipment condition and how hard it is pushed. **Response:** The drafting team notes that Attachment 1 has been revised to add "capability" reported to the Planning Coordinator or Transmission Planner. If the gross MW capability reported to the Planning Coordinator or Transmission Planner varies seasonally, the drafting team intends that the highest of the various seasonal capabilities be used by the Generator Owner. If from year to year the capability for any specific season varies the entity may need to reevaluate their protection if the newest maximum gross MW capability has increased from that previously used. The drafting team does not anticipate that entities will unnecessarily change settings if the maximum gross MW capability decreases. Change made. 5. Stating in Options 1, 2, 5 and elsewhere in Att.1 that the reactive power output is, "…a value that equates to 150% of rated MW," conflicts with PRC-025 having said earlier that "Synchronous generator output pickup setting criteria values are determined by the unit's maximum seasonal gross Real Power capability [not rating]." Consequently, the step-by-step calculations can take different paths. Our understanding of what Option 5 requires for example is presented below: a. A generator is nameplated 750 MVA @ 0.90 PF and 18 kV, yielding real and reactive nameplate ratings for this component of 675 MW and 327 MVAR respectively. b. The summer and winter net real power capabilities of this unit (limited by the boiler), as verified in seasonal testing, are 620 and 630 MW respectively, for which the gross outputs in the most recent verification were 655 and 665 MW respectively. The lower figure is to be used for PRC-025 purposes, because relay setting cannot be changed seasonally. c. The associated MVA at 0.90 PF is 727.778, and the current is 727,778/ (18 * sqrt3) = 23,343 A at the generator terminals, but let us assume that the GSU taps have been set under the TO's direction for 17.8 kV to correspond to the voltage schedule value of 232 kV. d. Criterion 1 of Option 5 sets the real power at 100% of the summer capability (655 MW), and criterion 2 sets the reactive power at 1.50 x 655 = 982.5 MVAR, so the total power output is SQRT (655^2 + 982.5^2) or 1180.818 MVA. e. The current is 1,180,818/ (0.95 * 17.8 * sqrt3) = 40,316 A at the generator terminals, ref. "Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage

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	times the turns ratio" under the "Generator Bus Voltage" column for Option 5. The pickup setting is to be no lower than 1.15 x 40,316 = 46,364 A @ 655 MW (92.7% overload relative to the 24,056 A corresponding to generator nameplate values of 750 MVA and 18 kV). Is this correct? It would be helpful to have an example calculation for each option in Att. 1, or (much better) a simpler expression such as saying that the pickup setting is to be no less than 200% of the current at generator nameplate MVA and voltage. **Response:** The drafting team notes that the maximum gross real power capability, regardless of whether or not different seasonal capabilities are reported, is used to determine the real power component of the complex power value used in these criteria. The value of the reactive power component is calculated by multiplying the MVA nameplate rating times the nameplate power factor rating yielding the MW, and further multiplying that MW by j1.5 (i.e., 150%) to arrive at the Mvar. For option 1 (now 1a), this complex power value is converted to impedance based on the rated system voltage multiplied by 0.95 and further multiplied by the transformer turns ratio. For option 2 (now 1b), the voltage on the generator bus is calculated by determining the complex voltage drop through the transformer starting with a 0.85 system voltage and the complex power is then converted to impedance using the calculated generator bus voltage. For option 5 (now 2a), the current at the relay is calculated in a manner similar to the example in NAGF's comment #5(e). **Response:** The drafting team has provided examples in the Guidelines and Technical Basis to improve the clarity. Change made. 6. Achieving PRC-025 compliance as well as desired protection goals may at times require replacement of major equipment, not just relays. A generator built to the present edition of ANSI C50.13 should be able to withstand a field forcing current of 226% for 10 sec, which appears to cover the requirements of PRC-025 depending on whether or not our calculations above are what the SDT intended. This figure was 208% in earlier editions of C50.13, which should also be sufficient. The assumption that loadability relay coordination involves exclusively generator short-term

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	overheating considerations ("field forcing is limited by the field winding thermal withstand capability") may not be correct, however. Not all units include the high initial response AVRs needed to reach the ANSI C50.13 limits shown above, and PRC-025 states in fact that only 20% of units examined were able to generate MVARS at the 150% of rated MW level mandated in the draft standard. A GSU sized to cover a generator with lesser field-forcing capability would be suitably specified for the application, but left exposed to damage by the PRC-025 settings criteria. The situation is the same or worse for auxiliary transformers, for which PRC-025 sets entirely new requirements. This is not a minor concern. In addition to the thermal damage posed in some cases by PRC-025 settings, transformers subjected to excessive current may instantaneously incur mechanical damage in the form of buckling of inner windings, stretching of outer windings, spiraling of end turns in helical windings, collapse of yoke insulation, press rings, press plates and core clamps, conductor tilting, conductor axial bending between spacers, and dielectric failures. The fundamental issue appears to be that the Application Guidelines are patterned on transmission line-loading practices, but GSUs and (especially) auxiliary transformers are not used and short-term-overloaded like transmission transformers, so requiring a minimum allowable trip pickup threshold based on IEEE C37.91 alone is not appropriate. Entities should be allowed to protect their equipment from overload, rather than being forced to allow a specific amount of overload. This objection gains force from FERC's March 15, 2012 FFT Order to propose specific standards or requirements that should be revised or removed [or not enacted in the first place] due to having little effect on reliability or because of compliance burdens. That is, PRC-025 imposes a worst-case (top 20%) current-withstand criterion on all plants, regardless of whether or not such an extreme requirement is applicable, imposing substantial burden with no identifiable benefit for perhaps 80% of all NERC-registered units. An exception should be made similar to the one proposed in some of the recent generator verification standards, such as, "Each Generator Owner of an existing generating unit or generating plant shall document non-relay limitations that prevent a generating unit or generating plant from meeting the criteria in Attachment 1, including study results or a manufacturer's advisory."

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	Retrofits could then be pursued only if and where the Planning Coordinator's simulations of Disturbances indicate that a genuine justification exists. **Response:** The drafting team notes that the standard does not require that the generator achieve the Mvar capability during conditions anticipated by the standard, but instead that the load-responsive protective relays accommodate whatever field forcing may occur during disturbances. Actual observed generator performance during disturbances, as well as numerous simulations using actual generator data, have shown that many generators may approach this value of field forcing. The drafting team understands that not all generators will be able to achieve this performance , and has offered the opportunity to perform simulations with specified criteria in order to determine the expected performance of a specific generator and application in order that the load- responsive protective relays may be set in a manner more precisely representative of that generator's performance. Therefore, an additional exception process is not warranted. The drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. Additionally, the overall "load" current represented by the criteria within this standard is approximately 200% of the continuous capability of the GSU transformer, and is well within the transformer capability as established by IEEE C57.109-1993. No change made. 7. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. **Response:** The drafting team notes that the Mvar performance specified within the criteria does not represent an intentional operating point but is instead a natural behavior of generator excitation systems to abnormal system conditions. The level of field forcing that will occur during abnormal system conditions is not affected by compromised equipment. The Mvar capability is a function of

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	the field forcing capability of the exciter/field during a system disturbance. The drafting team does not believe that entities will change settings when the unit is de-rated. No change made. **8**. PRC-025 appears to prohibit loadability relays from having multiple definite-time set points or a continuous inverse-time characteristic, due to not providing a cut-off time for the settings specified in Att. 1. That is, for the example of comment #5 above, dual ANSI C50.13-based settings of 54,366 A (216% current) for 10 sec and 37,046 A (154% current) for 30 sec would be unacceptable, as would a microprocessor relay I*t curve that follows the field short-term capability. Both would need to be replaced by a single trip setting of at least 46,364 A for the field forcing time (unstated in PRC-025 but understood to be max 10 seconds). **Response:** The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. No change made. Such an approach to loadability settings would degrade rather than improve BES reliability, by subjecting generation equipment to an increased risk of damage. There are many cases in which overload pickups at approximately 115% to 130% of the unit rating, for example, saved units with a low-level fault or exciter malfunction that caused an extended, moderate overload. Some presently-undefined alternative protective scheme would be needed were PRC-025 to go into effect in its present form, and the SDT apparently anticipated such concerns when stating in R1, "…while maintaining reliable protection." This optimistic statement avoids rather than solves the problem at hand; however, the discussion in the Application Guidelines of blinders and lenticular characteristics notwithstanding, nor is it evident why existing protection schemes that are effective and appropriate should be banned. **Response:** The drafting team notes that application of fault protective relays for overload protection does not represent the long-term nature of overload concerns. Overload protection is better provided by available protective devices and strategies that have response characteristics specifically focused in the time domain of overload protection, which would be delayed well past the time during which the generator excitation system constrains reactive output to acceptable

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	steady state values. No change made. The emphasis on "…while maintaining reliable protection" is intended to illustrate that an entity must adhere to these requirements while maintaining effective fault protection. The standard has been modified to "…while maintaining reliable fault protection." Results of actual major disturbances, explicitly the August 2003 event, have demonstrated that the existing protection practices are NOT effective during stressed system conditions. The IEEE is quoted in the PRC-025 Application Guidelines as saying, "it is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine-generator." The SDT has instead proceeded directly to specifying mandatory criteria despite the circumstance that, pending detailed and time-consuming analyses, there is no way of knowing whether or not it will be physically possible to comply. **Response:** The drafting team notes that the performance being addressed by this standard occurs for a time duration of several seconds, well beyond the trip time of fault protective relays. The drafting team believes that the criteria within this standard must address the sensitivity of the relays and that relay timing is not a factor. Additionally, the drafting team observes that using fault protective relays (with time delay settings related to fault protection) are misapplied if used for thermal overload protection, and that devices designed explicitly for that purpose should instead be used. The entity still must assure that protective device coordination exists as specified in other reliability standards. Attachment 1 is organized such that the simplest methods of analyses are presented first and analyses of increasing complexity follow for each different protection technology. The analyses of increasing level are presented such that if the simplest calculations are ineffective more precise methods are available. No change made. GOs are thus being asked to sign a blank check. We suggest that NERC instead put this standard in abeyance and call for GOs, OEMs and industry groups (IEEE, EPRI, NAGF) to investigate the matter, report present loadability relay settings, field winding thermal withstand capabilities and other limitations, and review the results with TOs and TOPs to identify a consensus course of action.

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	Response: The drafting team notes that the drafting team notes that the discussion from IEEE C37.102 is included in the Guidelines and Technical Basis in order to make this discussion available to entities. However, the drafting team is moving beyond the general application guidance expressed in C37.102 in order that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. No change made. 9. The meaning of the word “overall” is unclear in Applicability paragraph 3.2.3, “Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online.” It should be replaced by the term “generator bus or high side-to-medium voltage,” as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying “running power” to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. 10. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team believes that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator’s system

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	restoration plan (i.e., SRP), if identified as being BES. No change made. 11. The simulations referenced in Options 3, 7, 11 and 15 bear clarification. We believe that dynamic simulations are not intended; since the entire regional grid must then be modeled to achieve valid results, and independent GOs do not and cannot have access to mathematical representations of the T&D portion of the system. If this is in fact what is wanted, however, the standard should be made applicable also to TOs and TOPs, to create and run the models. Steady-state (e.g. ETAP) models would require substantial manual intervention to represent the Disturbance conditions of PRC-025, resulting in something that might be properly termed an engineering estimate but would not really qualify as a simulation. We need to know the criteria that auditors will look-for in enforcing PRC-025, e.g. degree of detail, time scale and boundary conditions. **Response:** The drafting team believes that the dynamic performance of individual generators can be simulated by modeling the generator at an output of the maximum gross real power capability at normal system voltage, and subsequently reducing the system voltage to 0.85 per unit. The generator performance (within the simulation) is then observed to determine the maximum value of reactive power output. Change made. The drafting team notes that the initial conditions for simulation are described in the new section in the Guidelines and Technical Basis titled Synchronous Generator Simulation Criteria. Change made. 12. Regarding voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be as high as specified in the draft standard. **Response:** The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 13. Using the term “apply settings” rather than “install settings” in Requirement R1 better suits the accepted terminology for setting the protective device parameters.

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	Response: The drafting team agrees, and has modified the standard as suggested. Change made. 14. The phrase "while maintaining reliable protection" in Requirement R1, as explained in the Rational for R1 and the introductory paragraphs of the Guideline and Technical Basis section, may not be compatible with "achieving …desired protection goals". In many instances found in the minimum allowed sensitivity settings in Table 1, the desired protection level is more conservative so that generation equipment is not allowed to operate in overloaded conditions. Experience has revealed that the pickup settings of generator protection systems can be set much lower than the values specified in Table 1 and not result in undesirable nuisance tripping. **Response:** The drafting team intends that this phrase emphasize that entities must still "adequately" protect their equipment. However, an entity may need to perform modifications to its protective relays or protection philosophies to achieve the required protection to satisfy this standard. The drafting team also notes that such nuisance tripping is undesirable, and has exacerbated actual serious disturbances. The standard provides that the Generator Owner may perform simulations to determine the actual generator performance during the stressed conditions anticipated by the standard which is a more precise option. No change made. 15. The suggestion made in the last paragraph of the Guidelines and Technical Basis document section Phase Distance Relay (Options 1-1) on page 18 causes concern. Suggesting that an entity's existing protection philosophy must be modified so that Table 1 setting criteria can be said to meet reliable protection is not appropriate. The existing (more conservative) philosophy of protection used by many companies has proven (over multiple decades) to be adequate for protecting equipment and providing reliable power supply to customers. **Response:** The drafting team notes similarly to the loadability requirements imposed on Transmission Owners by PRC-023-2 – Transmission Relay Loadability, long-used traditional protective applications (particularly electromechanical relays) may no longer be able to achieve the desired protection goals while supporting the overall system performance necessary to achieve reliable system operation. In many cases, existing protection was installed when considerably different paradigms were in place for operation of individual system components as related to operation of the system overall,

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	and traditionally conservative approaches have been demonstrated (by several major system disturbances) to not be adequate for overall BES reliability. For example, it may not be appropriate to continue to use time-delayed step distance relays to provide remote fault backup protection and breaker failure protection. Overly conservative settings (both for transmission lines and generators) in the 2003 Blackout increased the severity of the event. No change made.
Response: Thank you for your comments, please see the responses provided above.	
Exelon	-Please clarify if the scope of this Standard includes the protection for the leads connecting the high voltage side of the Generator Step up Transformer to the output breakers/buses in the switchyard. If so, what are the protection requirements? If not, which Standard or Standard under development project is intended to cover the protection system for this section? **Response:** The drafting team has identified the concern raised about the overlap between PRC-025-1 and PRC-023-2. The team has submitted a supplemental Standards Authorization Request (SAR) to the Standards Committee in January 2013 to resolve confusion and any overlap while ensuring no gaps in reliability are created. Additionally, the drafting team revised the Applicability section of the standard to include generation interconnection facilities. Change made. -Table 1 lists the number of options incrementally across all relay types (1-17) rather than grouping options by relay type. It may be clearer to identify the options in groups by relay type. **Response:** The drafting team has restructured Table 1 and the Guidelines and Technical Basis to provide more clarity. Those changes include; grouping by application (i.e., Generator, GSU, UAT, and lines), relay type (i.e., 21, 51, 51V-C, 51V-R, and 67), and the available option which may be only one option for the application or multiple options (e.g., a, b, or c). Change made.
Response: Thank you for your comments, please see the responses provided above.	
PPL and Affiliates	1. The meaning of the word “overall” is unclear in Applicability para. 3.2.3, “Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s)

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	online." The statement above should be replaced by "Auxiliary transformer(s) that supply HV or generator bus-to-MV transformers supporting auxiliary loads required for the unit to operate." as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change. ***Drafting team observation:*** *PPL #1 has made changes to phrases used in NAGF's comment #9 in Question #5 above. The modified comment is noted below for reference.* ***Reference:*** NAGF #9: "The meaning of the word "overall" is unclear in Applicability paragraph 3.2.3, "Auxiliary transformer(s) that supply overall auxiliary power necessary to keep generating unit(s) online." **The statement above** ~~**It**~~ should be replaced by ~~**the term "generator bus or high side-to-medium voltage,"**~~ **Auxiliary transformer(s) that supply HV or generator bus-to-MV transformers supporting auxiliary loads required for the unit to operate** as it may be impractical to analyze transformer protection settings down to the MV-to-LV level. This suggested approach seems to be in accordance with Fig. 1 and 2 of PRC-025, and is therefore believed to constitute a clarification and not a change." **Response:** The drafting team notes that this term is intended such that the station auxiliary transformer(s) supplying "running power" to the generator are addressed, whether these transformers are connected to the system voltage or the generator bus. The drafting team does not intend that lower voltage auxiliary transformers be included. The ampere loading on these transformers will increase if the generator bus voltage is depressed, and the drafting team intends that the related load- responsive protective relays do not cause these unit auxiliary transformers (UAT) to trip and in turn cause the generator to trip. No change made. 2. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due tobeing black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study. Imposing on black start units requirements that are unnecessary for BES reliability will further discourage GOs from building such units.

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	Drafting team observation: *The last sentence in PPL #2 replaced the following clause in the last sentence of NAGF's comment #10 in Question #5 from, "…study, reasonable coordination study,* rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities." **Response:** The drafting team notes that PPL and Affiliates has submitted the same comment #2, as that prepared by the North American Generator Forum (NAGF), comment #10, found in Question #5. Please refer to drafting team's response to NAGF's comment #10 above. 3. An allowance needs to be made in PRC-025 for unusual operating conditions, provided that the TO and TOP are notified of such circumstances. Generators that have compromised cooling (e.g. temporarily limited to below-rated hydrogen pressure) will experience a commensurate reduction in the field forcing that can be accommodated, for example, and units with a thermal stability issue can be knocked-offline by vibration and potentially damaged if massively above-rated reactive power flow is attempted. **Response:** The drafting team notes that PPL and Affiliates has submitted the same comments #3, as that prepared by the North American Generator Forum (NAGF), comment #7, found in Question #5. Please refer to drafting team's response to NAGF's comment #7 above. 4. The currently "To be determined" VSLs should be defined before the standard is voted upon. **Response:** The drafting team understands and had decided to post this draft without VSLs in order to focus the attention on the requirements due to a filing deadline of September 30, 2013. The drafting team has developed VSLs in consideration of comments received. Change made.
Response: Thank you for your comments, please see the responses provided above.	

END OF REPORT