NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2007-09 Generator Verification
PRC-019-1

The Project 2007-09 Generator Verification Standard Drafting Team (GVSDT) thanks all commenters who submitted comments on the proposed revisions to PRC-019-1. The standard was posted for a 30-day public comment period from September 28, 2012 through October 31, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 47 sets of comments, including comments from approximately 153 different people from approximately 99 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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.[1]

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

Summary Consideration

A large majority of stakeholders agree with the change in the VRF revisions and no stakeholder provided comments suggesting that they should be further revised.

A large majority of stakeholders agree with the revised VSLs. The GVSDT received one suggestion for revisions but the team felt that the proposal would add confusion rather provide further clarity to the VSLs.

Based on the stakeholder comments below, the GVSDT made the following minor edits and clarifications to the standard:

- Added specific language to the Effective Date section to clarify that certain regulatory bodies approve standards differently.
- Changed “AVR” to “automatic voltage regulator” in Requirement R1 (AVR is not a defined term).
- Removed the word “review” from Measure M2.
- Added a reference in Section F for IEE C50.13-2005.
- Removed "Converter Over-temperature limiter and associated protection function" from the example of Section G (Reference Information) because it is not a element that can be coordinated.

Index to Questions, Comments, and Responses

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	Mike Garton	Domion	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
2.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	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 KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5

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

4.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	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.	John Allen	City Utilities of Springfiel	SPP	1, 4
3.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6
4.	Sean Simpson	Board of public utilities of kansas city	SPP	1, 3, 5
5.	Mark Wurm	BPUK	SPP	NA
6.	Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
7.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
8.	Brian Taggert	Westar Energy	SPP	1, 3, 5, 6
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
10.	John Mayhan	Omaha Public Power District	MRO	1, 3, 5
11.	Ron McIvor	Omaha Public Power District	MRO	5, 1, 3
12.	Mahmood Safi	OPPD	MRO	1, 3, 5
13.	Anna Wang	Burns McDonald	SPP	NA

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	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	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

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

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
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
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.	Michael Schiavone	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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	Dewayne Scott		SERC	1
5.	Tom Vandervort		SERC	5
6.	Annette Dudley		SERC	5
7.	Paul Palmer		SERC	5
8.	Goerge Pitts		SERC	1
9.	Robert Bottoms		SERC	
10.	David Marler		SERC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1

Additional Member	Additional Organization	Region	Segment Selection
3. Erika Doot	Generation Support	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Larry Raczkowski	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William J Smith	FirstEnergy Corp	RFC	1
2. Steve Kern	FE Energy Delivery	RFC	3
3. Doug Hohlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstEnergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	paul haase	Seattle City Light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. pawel	krupa	WECC	1
2. dana	wheelock	WECC	3
3. hao	li	WECC	4
4. mike	haynes	WECC	5
5. dennis	sismael	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Frank Gavvney	Florida Municipal Power Agency	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Joe Stonecipher	Beaches Energy Services	FRCC	1
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7. Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	E Scott Miller	MEAG Power	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Steve Jackson	MEAG Power	SERC	3
2. Steve Grego	MEAG Power	SERC	5
3. Danny Dees	MEAG Power	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Thomas McElhinney	JEA	X		X		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.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. 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
13. Group	Jason Marshall	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
2.	John Shaver	Southwest Transmission Cooperative	WECC	1
3.	Tom Alban	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
6.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
7.	James Manning	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. 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
15. Group	David Dockery, NERC Reliability Compliance Coordinator	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Central Electric Power Cooperative		SERC 1, 3										
2.	KAMO Electric Cooperative		SERC 1, 3										
3.	M & A Electric Power Cooperative		SERC 1, 3										
4.	Northeast Missouri Electric Power Cooperative		SERC 1, 3										
5.	N.W. Electric Power Cooperative, Inc.		SERC 1, 3										
6.	Sho-Me Power Electric Cooperative		SERC 1, 3										
16.	Individual	Shammara Hasty	Southern Company	X		X		X	X				
17.	Individual	David Thorne	Pepco Holdings Inc and Affiliates	X		X							
18.	Individual	ryan millard	pacificorp	X		X		X	X				
19.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
20.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
21.	Individual	Nicole Buckman	Atlantic City Electric Company			X							
22.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
23.	Individual	Mark Yerger	Potomac Electric Power Company			X							
24.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
25.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
26.	Individual	Winnie Holden	PSEG	X		X		X	X				
27.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
28.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP (Voting entity Occidental Chemical Corporation)					X					
29.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
30.	Individual	Saul Rojas	New York Power Authority	X		X		X	X			X	
31.	Individual	Thad Ness	American Electric Power	X		X		X	X				
32.	Individual	Michael Falvo	Independent Electricity System Operator		X								
33.	Individual	Wryan Feil	Northeast Utilities	X									
34.	Individual	Brian Evans-Mongeon	Utility Services								X		
35.	Individual	Daniel Duff	Liberty Electric Power LLC					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
36.	Individual	Mahmood Safi	Omaha Public Power District	X		X		X	X				
37.	Individual	Scott Berry	Indiana Municipal Power Agency										
38.	Individual	John Martinsen	Snohomish County PUD No.1	X		X	X	X	X			X	
39.	Individual	Mike Hirst	Cogentrix Energy					X					
40.	Individual	Mary Downey	City of Redding			X	X	X	X				
41.	Individual	Maggy Powell	Exelon Corporation and its affiliates	X		X	X	X	X				
42.	Individual	Kirit Shah	Ameren	X		X		X	X				
43.	Individual	Don Jones	Texas Reliability Entity										X
44.	Individual	Joe Tarantino	SMUD	X		X	X	X	X				
45.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
46.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
47.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					

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).

Organization	Supporting Comments of “Entity Name”
MEAG Power	Southern Company Services, Inc. - Gen
Delmarva Power & Light Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Atlantic City Electric Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Potomac Electric Power Company	Potomac Electric Power Company, Transmission Owner (Segment 1)
Liberty Electric Power LLC	NAGF
Snohomish County PUD No.1	Snohomish County PUD No.1 (SNPD) supports New York Power Authority (NYPA) comments.
Indiana Municipal Power Agency	Indiana Municipal Power Agency agrees with the comments submitted by the North American Generator Forum for PRC-019.
City of Redding	SMUD/BANC
Brazos Electric Power Cooperative, Inc.	ACES Power Marketing
Nebraska Public Power District	MRO NSRF

1. **The GVSDT revised the VRFs to "Medium" based on stakeholder feedback. Do you agree with the proposed revision? If not, please provide an alternative and supporting information in the comment area below.**

Summary Consideration: A large majority of stakeholders agree with the change in the VRF.

The consensus of stakeholders submitting comments was that an assignment of Medium VRFs was appropriate.

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative, Inc. - JRO00088	No	AECI does not believe R1 should exist as currently drafted, see below.
Response: The GVSDT thanks you for your comment. The comment does not address the question asked. Please see the response to your comment in Question 3 below.		
Cowlitz PUD	No	Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Response: The GVSDT thanks you for your comment. The GVSDT is required to assign VRF's as part of the drafting process.		
Manitoba Hydro	Yes	None.
PPL Corporation NERC Registered Affiliates	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc and Affiliates	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
ACES Power Marketing Standards Collaborators	Yes	
pacificorp	Yes	
Southern Company	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Yes	
American Transmission Company	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 1 Comment
New York Power Authority	Yes	
Northeast Utilites	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Ameren	Yes	
Exelon Corporation and its affiliates	Yes	
Texas Reliability Entity	Yes	

2. The GVSDT revised the VSLs for each requirement based on stakeholder feedback. Do you agree with the proposed revisions? If not, please explain in the comment area below.

Summary Consideration: A large majority of stakeholders agree with the revised VSL's.

Organization	Yes or No	Question 2 Comment
Ameren	No	(1)Although we prefer a % of Facilities approach, we can accept the R1 VSL revision with the stated time frames. **Thank you.** (2)A time-based VSL does not align with the severity of failing to meet R2. The severity is primarily a function of the amount of on-line exposure. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. We request that for R2 the SDT replace the time-based (days late) with % of MWh during the period of violation to more properly account for aggregate impact and restate the R2 VSL as follows:(a)Lower VSL becomes 'The Generator Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing from 0% to 5% of their total MWh generated during the violation period.' This does require each unit to be coordinated. (b)Moderate VSL becomes '...more than 5% and less than 10%' (c)High VSL becomes '...more than 10% and less than 15%'(d)Severe VSL becomes '... more than 15%'.(3)We request that the SDT insert 'latter of' before 'identification or implementation' in R2 VSL if the SDT does retain the time-based VSL format. Identification differs from implementation so clarity is needed if a violation does occur. **Using a structure as suggested does not meet the NERC guidelines for VSL development. In addition, the GVSDT believes this would be much more complex to administer. No change made.**
Response: The GVSDT thanks you for your comment. See response to specific comments above.		

Organization	Yes or No	Question 2 Comment
Cowlitz PUD	No	Do not agree with the Standard requirement structure; therefore, it is too early to assign VRFs.
Response: The GVSDT thanks you for your comment. The GVSDT is required to develop VRF's and VSL's as part of the drafting process.		
seattle city light	No	New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The GVSDT believes there is a reliability benefit to reviewing coordination every five years because limiter and protection settings may be changed by somebody other than the person responsible for the coordination review and the effective system impedance (which affects the SSSL) may easily change without the Generator Owner's knowledge.		
Manitoba Hydro	Yes	None.
Southwest Power Pool Reliability Standards Development Team	Yes	
Pepco Holdings Inc and Affiliates	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Luminant	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ACES Power Marketing Standards Collaborators	Yes	
pacificorp	Yes	
Southern Company	Yes	
TransAlta Centralia Generation LLC	Yes	
PSEG	Yes	
Xcel Energy	Yes	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Yes	

Organization	Yes or No	Question 2 Comment
American Transmission Company	Yes	
American Electric Power	Yes	
Wisconsin Electric Power Company	Yes	
Independent Electricity System Operator	Yes	
New York Power Authority	Yes	
Northeast Utilites	Yes	
Omaha Public Power District	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation and its affiliates	Yes	
Texas Reliability Entity	Yes	

3. Do you have any other comment, not expressed in questions above, for the GVSDT?

Summary Consideration: Based on the stakeholder comments below, the GVSDT made the following edits and clarifications to the standard:

- **Added specific language to the Effective Date section to clarify that certain regulatory bodies approve standards differently.**
- **Changed "AVR" to "automatic voltage regulator" in Requirement R1 (AVR is not a defined term).**
- **Removed the word "review" from Measure M2.**
- **Added a reference in Section F for IEE C50.13-2005.**
- **Removed "Converter Over-temperature limiter and associated protection function" from the example of Section G because it is not a element that can be coordinated.**

Organization	Question 3 Comment
ACES Power Marketing Standards Collaborators	(1) R1 should be modified to clarify that the GO or TO shall coordinate their applicable Facilities. While most readers would interpret the requirement to apply to the Facilities owned by the GO and TO, it simply does not say this. We recommend using "each GO and TO shall coordinate the voltage regulating system controls ... applicable equipment capabilities of its applicable Facilities and the settings of the applicable Protection System devices and functions." **The GVSDT believes that the applicability section adequately prescribes the scope of the facilities and declines to make this change.** (2) While we disagree with the inclusion of blackstart units in this standard, the previous wording was actually more correct and consistent with the Statement of Compliance Registry Criteria. Changing "Blackstart Resource" to "blackstart unit" only causes confusion and ambiguity. By definition a "Blackstart Resource" is a blackstart unit that is included in the Transmission Operator's restoration plan. Since the applicability section also states that the blackstart unit must be included in the TOP's restoration plan, it is not clear what was accomplished with changing Blackstart Resource to blackstart unit. It causes the reader to question what additional units are intended if

Organization	Question 3 Comment
	they don't mean Blackstart Resource. Furthermore, it deviates from the wording in the Statement of Compliance Registry Criteria. This is contrary to the response that was provided to a comment by PSEG to change the language during the last posting. The response indicated that the "SDT feels it is best to retain the NERC wording without modification." We can find no other citation in the response to comments indicating a reason to change it. Please change blackstart unit back to Blackstart Resource. **The compliance registry criteria V5 document, paragraph III.c.3 is shown below….** III(c) Generator Owner/Operator: III.c.1 Individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or; III.c.2 Generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating, or; III.c.3 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a transmission operator entity's restoration plan, or; III.c.4 Any generator, regardless of size, that is material to the reliability of the bulk power system. **Section 4.2.4 of the draft standard matches this registry criteria wording exactly.** (3) In applicability sections 4.2.1 through 4.2.3, please change "directly connected to the BES" to "that are part of the BES". Per the BES definition, generation units can be and are part of the BES. Using "directly connected to the BES" could draw in a non-BES unit. **The existing wording more closely matches V5 of the registry criteria and will be retained.** (4) There is an extraneous comma in R2.

Organization	Question 3 Comment
	The sentence structure has been altered slightly to address this concern.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Ameren	(1)R2 is unclear as written, please insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. **The GVSDT believes that the existing wording is adequate to ensure that the protection elements are coordinated.** (2)Attachment 1 Example appears to violate R1 1.1.2. Loss of Field Zone 2 trips before 'operating conditions exceed equipment capabilities.' On the other hand, it would certainly 'limit the extent of damage when operating conditions exceed equipment capabilities or stability limits' since it trips before either of them are reached. This example does show how specialized and complex this coordination is. Entities may have different margins, asset protection, and operating practices. We presume the SDT intends that the examples show 'coordinated' capabilities, controls, and protection. If not, the lack of coordination should be pointed out. **The coordination shown in the example of Attachment 1 is simply that: an example of a system demonstrating the coordination of the settings with respect to an example protection philosophy. This draft standard does not specify margins, asset protection limits, or operating practices. Entities are obligated to review the protection elements to ensure that gross errors do not exist which may result in undesired premature tripping or extensive damage to equipment which contributes to the reliability of the power system.** (3)We request that the GVSDT make all the papers listed in the reference section of the standard readily available on the NERC website. **Copyright laws do not permit this publication the references provided should provide adequate information to allow entities to obtain copies of the documents.**

Organization	Question 3 Comment
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Florida Municipal Power Agency	1) R1 can be misinterpreted to require a full-blown coordination study every 5 years even if nothing at the plant had changed. There should be a qualifier saying that past coordination studies are still valid if nothing has changed, but that at minimum a review is needed every 5 years to see if the existing coordination study is still valid. **A previously completed coordination study can be used as a baseline or starting point for this recurring requirement. If nothing has changed in the system since the previous coordination, the required action could amount review and confirmation of the previously determined coordination.** 2) A synchronous condenser can be owned by either a TO or GO. For instance, there are installations of generators where a clutch is installed to separate the electric generator from the prime mover to run the electric generator as a synchronous condenser. Such a synchronous condenser would be owned by a GO. The standard should not force a GO to register as a TO simply because it owns a synchronous condenser. FMPA recommends making the requirement applicable to a GO or TO who owns a synchronous condenser. **Draft standard sections 4.1.1 and 4.2.2, taken together, make this standard applicable to GO's with synchronous condensers.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Texas Reliability Entity	1) Does the SDT foresee any conflicts between the proposed language in PRC-019-1 and the proposed setting limits in PRC-025-1, Generator Loadability? **There appears to be industry concern over the "relaxed" protection thresholds currently specified in the draft PRC-025 standard with regard to minimizing equipment damage from overloads. R1.1.1 of the draft PRC-019 has the same objective as PRC-025.** 2) The SDT may want to include a reference ANSI C50.13-2005 for proper coordination of the over/under excitation limiters with AVR, equipment capabilities, and loss-of-field, and other

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	protective functions. **As the referenced document contains design rating considerations for cylindrical-rotor synchronous generators rated 10MVA and above, it can be a useful document when performing the proposed requirements of this standard. It will be referenced in the associated documents section F.** 3) Measure M1: Evidence should also include documentation that actual settings for relays, AVRs, and limiters match the coordination study. **This is superfluous and not necessary. The coordination plots, settings table comparisons, or other methods used to verify coordination are visual representations of the settings that reside in the protective devices. They, by definition, are the same as the actual settings. Otherwise, the coordination studied is not a review of the coordination which is specified in R1 of the draft standard.** 4) Considering the proposed new BES definition and the Guidance Document, there may be confusion in determining if a generator is "directly connected" to the BES. Please consider reviewing the language to see if it should instead say "included in" the BES. Note that a BES generator can be connected to the BES by non-BES elements, and arguably not "directly connected" to the BES. See, for example, figures E1-4 and E1-6 in the BES Definition Guidance Document. **Until the BES definition document is completed, any change to the applicability section of this draft standard is premature. The applicability section of this draft standard matches, very closely, the verbage of version 5 of the NERC Statement of Compliance Registry Criteria, section IIIc.** 5) In general, the Protection System changes should be coordinated before energization (or re-energization) following a change. Is the 90 day time period in R2 consistent with the expectations of PRC-001? **That is true, in general. Utilities generally will not commission new protective relaying without consideration of the application of appropriate settings for the devices. Without this consideration, the protection equipment will either not provide adequate protection or will trip**

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	the equipment premature to necessity. The GVSDT believes that requirements R1 and R2, as drafted, are adequate to confirm that the proper coordination exists. Rather than detailing every possible change which can affect the coordination and specifying timelines for compliance for each type of change, the drafting team elected to present the requirement as provided.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Duke Energy	1) Section 1.1: Reword to clarify "normal" is describing the AVR control mode only. Also, SDT should consider mentioning weak system operating conditions are typically used when coordination with the SSSL. Suggested rewording: "Under steady-state system operating conditions, and assuming normal AVR control loop conditions, verify the following coordination items for each applicable Facility:" **"The" was added to R1.1 to emphasize that normal applies to the AVR control mode.** 2) Section 1.1.2: Strike this section, as it is outside the scope of this document. It appears to be mandating protection. PRC-019-1 should be focused on settings. **The words "applicable, in-service" qualify that an entity must consider minimizing the extent of damage to equipment through the settings of protection that he has elected to place in-service. The requirement does not dictate that such protection be placed in-service.** 3) Page 7/11: (Reword 2nd paragraph) Examples of limits, limiters, protection which must be coordinated if employed include: **As this section is simply a section indicating examples of the types of protective functions which may be applied on a generating unit. The NOTE in this section specifies that this section is for reference only, and does not specify additional requirements. The use of "must be coordinated if employed" is not appropriate for an example section. The requirement for inclusion of protective elements which are in service is located in R1, where it should be located.** 4) Page 7/11: Remove all the words "associated" in second paragraph. **The GVSDT believes that "associated" is necessary in this paragraph to make it clear that the protective functions listed in each line item are those that are associated with a particular**

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	protective function. 5) Page 7/11: Remove section on SSSL calculation. Does not belong in standard, see references listed as needed. **This section was added during a previous revision to this standard at the request of multiple commenters.** 6) The unit size applicability for PRC-019 and MOD-025 should be set equivalent to that specified by MOD-026 and MOD-027. We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **The coordination review, practically, should be done just prior to the reactive testing specified by MOD-025 so that the protection does not operate undesirably during the testing. The applicability of PRC-019 and MOD-025 are set to match each.** 7) The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes that 5 years is a more appropriate interval for this review.** 8) Strike “Convertor Overtemperature” from this list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. **The standard has been revised to address your concern.** 9) R2 specifies “perform the coordination” while M2 states “coordination review” - we believe that R2 and M2 should be consistent. **The standard has been revised to remove “review” from R2 and M2.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	

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Wisconsin Electric Power Company	1. In R1.1.2, we suggest revising the sentence to : "The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage...". **The GVSDT slightly modified this statement to state the requirement more clearly.** 2. In R1, there needs to be a way for entities to take credit for coordination studies done in the last 2 years prior to the effective date of this standard. **There is no wording to prevent this. Once the standard is in effect, the entity must have 40%, 60%, 80%, and 100% of their applicable units compliance in two years, three years, four years, and five years, respectively. The entity can choose the scheduling order. If an entity has already completed coordination studies and has evidence to prove it at the time of the effective date of this standard, then (barring no changes that invokes R2) they need only to review the coordination before the 5 year time frame to maintain compliance with R1.** 3. In R2, the 90 day requirement to document coordination following a change is not reasonable. It may not be possible to obtain the necessary information from equipment vendors in this timeframe. We suggest a time of 180 days for this requirement. **The GVSDT believes that the 90 day time frame is adequate.** 4. It is not clear how these requirements would be satisfied at wind farms. None of the example information in Section G Reference appears to be applicable to wind farm equipment. We suggest that wind resources be specifically exempted from this standard.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Cogentrix Energy	1. R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, **The GVSDT has revised the standard in an attempt to ensure that coordination of the protection system will occur. If no changes have occurred, a review of the previous coordination will suffice.**

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	2. It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1. **The GVSDT believes that the draft standard adequately prescribes that only those elements which are in service are subject to being included into the coordination study. Also, please see the NOTE on p7 of Draft 3 of the draft standard with regard to not requiring installation or activation of limiters or protective functions.** 3. The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. That is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. **The listing provided in section G is not meant to be prescriptive. It is to be used for example only. The NOTE in that section reflects this. The phrasing in paragraph 2 of page 7, "limiters and protection functions which could be coordinated include (but are not limited to). The list is representative of functions which typically are found in excitation control systems. Only those functions which are in service (at the choice of the entity) need to be addressed in response to this standard.** 4. The term "black start unit material" in applicability para. 4.2.4 (p.2) is not understood. We would object if the intent was to designate any unit that has the potential for black start capable conversion, in addition to units that are presently black start resources. GOs would, in this case, have to take on substantial burdens based on mere conjecture as to modifications that might (but probably would not) be made sometime in the future. **The wording used in applicability section 4.2.4 is taken directly from V5 of the NERC Statement of Compliance Registry Criteria, and clearly states that the units addressed here are those which are designated in the transmission operator's restoration plan.** 5. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in our possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable.

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	PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **For protective relay settings to be determined, some type of analytical comparison must be used to achieve coordination. Specifying that this documentation be included with any resultant relay settings or excitation system protection parameter settings should not add any considerable cost. The additional cost is simply including some documentation of the comparison method used to determine the relay/excitation control settings.** 6. The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes that the five year interval is more appropriate for PRC-019 and MOD-025.** 7. It is suggested to strike "Convertor Over temperature" from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not an element that can be coordinated. **The standard has been revised to address your concern.** 8. R2 specifies "perform the coordination" while M2 states "coordination review" - we suggest that R2 be changed to "review the coordination" **The standard has been revised to ensure that the protection system is coordinated.**
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Tennessee Valley Authority	1. Reference, Examples of Coordination, page 7 of 11, bullets at the top of page 7, Recommend deleting the word "associated" in all of the applicable bullets. Justification is that the word "associated" is not needed in these bullets and it will make the bullets more crisp. **The drafting team believes that the phrase "and associated protective functions" is necessary to suggest that those limiters have protective functions that require coordination. It is the responsibility of the entity to illustrate coordination between these limiters and their**

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	associated protective functions while maintaining generator equipment protection. 2. Standard, 4.2 Facilities, The unit size applicability for PRC-019-1 should be set equivalent to the unit size applicability found in MOD-026 and MOD-027-1 (i.e. MOD-026-1 Draft, 4.2, Facilities, 4.2.1, Generation in the Eastern or Quebec Interconnections ... (including 4.2.1.1, 4.2.1.2); 4.2.2 Generation in the Western Interconnection ... (including 4.2.2.1, 4.2.2.2); 4.2.3 Generation in the ERCOT Interconnection ... (including 4.2.3.1, 4.2.3.2). Justification is to be consistent across all generator verification standards (e.g. Generation in the Eastern Interconnection with individual units greater than 100 MVA, etc.) **The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.** 3. Requirement R1, Recommend changing the periodicity of this verification as stated “At a maximum of every five calendar years, ... “ to a recommended verification periodicity equal to PRC-005-2 Draft, Table 1-1, Component Type - Protective Relay, Maximum Maintenance Interval, “6 calendar years.” Justification is to coordinate protective system relay testing during plant outages with the voltage regulating controls and protections testing that can be performed during outage shut-down or start-up sequences. **The GVSDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection**

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	settings of generating equipment, the GVSDT feels that a five year verification of this characteristic is appropriate.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Independent Electricity System Operator	1. The effective dates in the proposed Implementation Plan and in Section A5.1 of the standard may conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by:a. In the Implementation Plan, under the Section "In those jurisdictions where regulatory approval is required:", adding a phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner..."b. In Section A5.1 of the standard, adding the same phrase ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities," right after "following applicable regulatory approval" and before "each Generator Owner...". **The GVSDT agrees to change the Effective Date wording to address your concerns. After consultation with NERC legal counsel, the following wording has been added: "… or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."** 2. The wording of R1 is confusing, since the required coordination shall be maintain all the time. We suggest a change of the wording as follows: the phrase "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls" should read "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall review the coordination of the voltage regulating system controls" ; Also, the phrase "1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily." should read" 1.1.1. The in-service voltage regulating control limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily."

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	The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Associated Electric Cooperative, Inc. - JRO00088	Applicability, Part 4.2.4, CHANGE: Remove this entire clause specific to Blackstart of units of any size, RATIONALE: AECI agrees with earlier Industry commenters that opposed the inclusion of these units and disagrees with the SDT's persistent inclusion. Inclusion of Blackstart units of any size, ultimately harms the grid reliability by imposing more regulatory-risk exposure upon them, such that our industry is already seeing many disappear from system restoration plans. With this trend left unchecked, and we are trying to piece our systems back together 10 years from now for whatever reason, the RCs will not even know that many of these viable units still exist. Many may have in fact been driven from existence by such well-intentioned laws having failed to consider the unintended consequences. In addition, the value of AVR functionality for Blackstart units is highly questionable during blackstart situations. **The GVSDT disagrees that Blackstart Resources should be removed from the applicability of this standard. When called upon to operate in their black-start mode, it would probably be under stressed transmission system conditions that could require the generator to provide reactive power to its limits (either leading or lagging). Given the critical nature of an actual transmission system recovery, having the black-start generator limiters and protection properly coordinated is essential.** Requirement R1, CHANGE: Redraft the language toward each responsible entity's internal controls program, RATIONALE: While AECI appreciates the initial 5-year time-line to "check the coordination of all our unit's in-service limiting "stuff", we see the R1 5-year revisit of no added value. This is in contrast to the value of R2's invoking the correct triggering mechanism for events that would precipitate rechecking such protective systems and setting's coordination. AECI simply believes R1 to be overly prescriptive and its existence, as currently drafted, will destine it for future removal. **The GVSDT appreciates your position but since a large majority of stakeholders has approved the**

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	standard as it is currently written the GVSDT chooses not to modify the wording at this time. At a time when the standard is reviewed by NERC staff, the change into another format would be considered.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Pepco Holdings Inc and Affiliates	Attachment 1 and Attachment 2 have been revised since the last draft. In these latest set of attachments, although the Zone 2 loss of field characteristic has been set to operate prior to the Steady State Stability Limit (SSSL) is reached, it is also set so that it would operate prior to the generator capability curve being exceeded. This appears to be in conflict with the intent of the standard to ensure that protection should not operate before the equipment capability is exceeded. The Zone 2 characteristic should properly be set between the Generator Capability Curve and the Steady State Stability Limit. As such, Figures A.6 and A.7 in IEEE C37.102-2006 might be better coordination examples to use for these attachments.
Response: The GVSDT thanks you for your comment. The examples for illustrating coordination between AVR limiters and protection examples in the Annex of IEEE C37.102 are very similar to the one in Section G of PRC-019. The drafting team appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the P-Q or R-X diagrams.	
Cowlitz PUD	Cowlitz supports the review performed by the NAGF SRT with modification: 1. Requirement R1 appears to have been written with ever-evolving T&D systems with multiple owners/planners in play where Protection System settings may require adjustment to assure proper operation. However, this is not the case for generation facilities which remain relatively static under single management until system improvements are made. Further, it is unprecedented to require a scheduled reassessment of system control settings without cause. The Standard Requirement R1 appears to assume it necessary to review past coordination engineering work and resulting system control and Protection System settings for errors every five calendar years. We see no reliability return in such activity. Requirement R1 must be centered on first establishing that proper coordination engineering and resulting system control and Protection System settings have been completed, and documentation of such work is

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	retained in a Generation Facility Control and Protection Manual. Requirement R2 then covers the cause for review - system improvements, equipment upgrades, new operation theory, etc. - that triggers a reassessment of the coordination engineering and if necessary a revision to the Generation Facility Control and Protection Manual. The only possible item that may merit a scheduled activity is to verify all settings have not inadvertently changed, and are in compliance with the current Generation Facility Control and Protection Manual. **Once the initial study has been completed, the entity is not required to perform a full study at the 5 year time frame. The only item that may have changed in the 5 year time period is the transmission system equivalent which would affect under-excitation limiters, loss of field relay, and steady state stability limit coordination.** 2. The nonexclusive nature of the listing in section G is a concern regarding proof ofcompliance. That is, it would be burdensome to have to document a rationale for all relaysand excitation system and voltage regulator functions for which a PRC-019-1 study is felt tonot be required. The sect. G list should be complete and exclusive. **The examples were offered as such: these are examples. The GVSDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the GVSDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** 3. The term “black start unit material” in applicability para. 4.2.4 (p.2) should be changed to the NERC defined term Blackstart Resource. Further, (departing from NAGF SRT Comments with suggested SDT response) it must be understood that Blackstart Resources must involve coordination between the TOP and the GOP. The TOP is not allowed to unilaterally designate blackstart capable resources within their restoration plan. EOP-005-2 mandates this via Requirement R13. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry**

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	Criteria. The GVSDT feels it is best to retain the NERC wording without modification.
Response: The GVSDT thanks you for your comment. Please see specific responses above.	
Ingleside Cogeneration LP (voting entity name Occidental Chemical Corporation)	Ingleside Cogeneration LP agrees that the proper coordination between a generator's voltage limiters, protective relay settings, and its stability limits can best assure its availability in response to transient conditions. However, we are concerned with the aggregate work load that all five standards in Project 2007-09 will place upon our engineering and operations organizations. Each has its own unique purpose, which means unique processes to support them - as well as test results that demonstrate compliance. With so much uncertainty surrounding this program, we cannot agree to proceed without the following items being addressed:1) All requirements for recurring assessments (R1) must contain language that focuses on the strength of the validation process - not the execution. This could be similar to that used in the CIP version 5 standards calling for the Responsible Entity to implement an action "in a manner that identifies, assesses, and corrects deficiencies". Experience has shown that without this preface, auditors will focus on missed due dates, whether or not all check boxes are filled in, and statements showing that every sub-requirement was addressed - even those not applicable to the facility. The CEA's focus needs to be on the entity's commitment to the validation effort, not the documentation.2) The Compliance organization needs to be engaged in the development process so that industry stakeholders have a sense of how adherence to the standard will be determined. The existing process is disconnected - leading to inconsistent interpretations of the drafting team's original intent. Other projects have begun to post drafts of the RSAWs concurrently with the standards for exactly this reason. The SDT should take note that these modifications are consistent with the risk-based compliance direction that both NERC and FERC support. The intent is to focus industry and regulatory resources on the reliability aspects of the initiative - not its administrative aspects.
Response: The GVSDT thanks you for your comment. Your issues relate to the "Find, Fix and Track" process that was most notably incorporated in the CIP body of standards. For example, CIP-003-5, Requirement R2 states:"Each Responsible Entity for its assets identified in CIP-002-5, Requirement R1, Part R1.3, shall implement, in a manner that *identifies, assesses, and corrects deficiencies*, one or more documented cyber security policies that collectively address the following topics, and review and obtain	

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CIP Senior Manager approval for those policies at least once every 15 calendar months:" This requirement relates to a specific program that addresses a wide range of topics, including documentation of the processes involved. The requirements of PRC-019 are to verify coordination of protection systems. Under this standard, the responsible entity either performed the verification or they didn't. There is no inherent program deficiency that can be identified and corrected. The GVSDT does not believe that this approach is applicable to the requirements that we have developed.	
JEA	JEA supports the comments of the NAGF and believes that the SDT team should accept a request by the NAGF to have a joint meeting to discuss and resolve the many differences since these differences are so substantial that the usual iterative process will be excessively long. We also support NAGF's suggestion to evaluate these standards using the Cost Effective Analysis Process.
Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not make substantive changes at this time.	
Luminant	Luminant recommends that Requirement R1 and Measure M1 be revised to clarify that the coordination described in the text is not between the Generator Operator and Transmission Operator. R1 would be revised in the following manner, "At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service 1imiters and protection functions) with its applicable equipment capabilities and settings of the applicable Protection System devices and functions. 1.1. Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility". Measure M1 would be altered in the same manner.
Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.	
seattle city light	New Requirement R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for

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	objection is that said coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The GVSDT considered that entities would want to verify the said coordination of R1 prior to performing the verification of MOD-025, thus the 5 year interval was chosen. The GVSDT chooses not to modify the interval at this time.	
Southern Company	Please consider placing the applicable unit size for PRC-019 and MOD-025 equivalent to that specified by MOD-026 and MOD-027. T**he GVSDT believes that using the Compliance Registry criteria is prudent for setting the applicability of this standard. The commenter did not provide a technical justification for a non-standard Applicability.** The periodicity of PRC-019 coordination and MOD-025 real & reactive capability should match that of PRC-005-2 for relay testing (6 years) rather than 5 years due to generating plant outage schedules usually being 1-1/2, 2, or 3 years, all of which are integral factors of a 6 year interval. **The GVSDT believes the five year interval will not present an undue hardship on Generator Owners considering the phased implementation plan. We are not aware of any generators that run continuously for more than five years.** We suggest striking “Convertor Overtemperature” from the list of typical limiting and protection examples in Section G, Page 7, as this feature is not a coordinatable element. **The GVSDT agrees that "Converter Overtemperature" is not a coordinatable element and has removed it from the example of Section G.** R2 specifies “perform the coordination” while M2 states “coordination review” - we believe that R2 should be changed to “review the coordination”R1 appears to have been written with evolving T&D systems in mind. It should be made clear that all that is required for a generation unit that has experienced no changes affecting the response in question is a review of the equipment state every 6 (six) years rather than requiring a new coordination study. **While the generator limiter and protection settings may not have changed, the equivalent system impedance may easily change which affects the SSSL.**

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Response: The GVSDT thanks you for your comments. Please see specific responses above.	
Manitoba Hydro	R1 - Manitoba Hydro finds the wording 'At a maximum of every five calendar years' awkward. We suggest changing the wording to read 'at least once every five calendar years'.R1.1.2 - Manitoba Hydro suggests deleting R1.1.2 which reads, "The applicable in-service Protection System devices are set to operate, isolate or de-energize equipment, in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits". Since these are fundamental functions of any protection system device, there is no need to include this in the NERC standard. R1.1.1 - Is AVR defined somewhere? We could not find its definition in the Glossary. **The GVSDT has replaced the term "AVR" with "automatic voltage regulator".** General Comments - 1. Manitoba Hydro has a concern with respect to the phased in implementation measured by percent compliance. We believe that this may lead to a potential for some uncertainty and debate. Does a phased in implementation such as this, do anything to increase reliability?. **The GVSDT believes the phased implementation program allows Generator Owners to coordinate any settings changes to limiters or protection systems with planned generator outage activities. No changes made.** 2. The concept of equivalent unit testing should be applied to both synchronous condensers and generators. Equivalent units are addressed in Row 5 of MOD-027-1 Attachment 1, but it is not clear if this attachment applies to PRC-019. We would suggest that "Attachment 1" from MOD-027-1 be added to all of the standards included in this project.3. Attachment 1 of MOD-026-1 (Note 2) and M0D-027-1 (Note 3) contain a section titled "Consideration for early Compliance" with language pertaining to previous testing and model verification which were completed under the applicable regional policies, guidelines or criteria or which are compliant with the requirements of the standard. Manitoba Hydro recommends that similar language be included in the other standards (PRC-019-1, MOD-025-2 and PRC-024-1). **There are no "equivalent unit" criteria for this standard and the wording used in MOD-027-1 Attachment 1 does not apply to this standard.**
Response: The GVSDT thanks you for your comments. Please see specific responses above.	
PPL Corporation NERC	R1 appears to have been written with ever-evolving T&D systems in mind. It should be made clear

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Registered Affiliates	that all that would be needed every five years for a generation unit that has had no changes affecting the systems in question is an attestation to this effect, not a new coordination study, It should also be made clear that the in-service limiters referenced in R1 and R1.1.1 pertain where they exist. That is, it is not necessary to have a pre-Protection-System limiter for every relay listed in sect. G of PRC-019-1 (i.e. there is not a relay that stands behind every limiter). **The GVSDT agrees that there may not be a Protective Relay behind every Limiter, and Section G is for "Example" only. The GVSDT believes that the Generator Owner is responsible for, and should posses the calculations to perform (or review) the coordination outlined by this standard.** Section 1.1.2 should be struck - as this is covered under the direction of other standards such as EOP-003. **The GVSDT disagrees that EOP-003 (Load Shedding Plans) cover coordination of generator voltage regulator limiters, protection and generator capabilities. No change made.** The non-exclusive nature of the listing in section G is a concern regarding proof of compliance. This is, it would be burdensome to have to document a rationale for all relays and excitation system and voltage regulator functions for which a PRC-019-1 study is felt to not be required. The sect. G list should be complete and exclusive. **The GVSDT cannot possible anticipate all existing and present protective functions that Generator Owners may apply to their equipment. No change made.** The term “blackstart unit material” in applicability para. 4.2.4 (p.2) is not understood. We suggest that the SDT remove the term “blackstart unit material” or clarify when a blackstart unit designated as part of the Transmission Operator’s restoration plan would be immaterial. **The wording in the Applicability section is directly from NERC’s Statement of Registry Criteria. No change made.** Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in a Generator’s possession. The calculations can be re-performed, but at substantial cost; and, excepting units that are critical to the BES, it is not clear that the required expenditure is justifiable. **Once the calculations are set up (in a spreadsheet, for example) reviewing, or recalculating with a new parameter, does not require significant effort. No change made.** PRC-019-1 should be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **Inadvertent tripping of any applicable generator could affect BES reliability. No change made.**

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Response: Thank you for your comments. See responses to specific comments above.	
Bonneville Power Administration	Regarding the "Functional Entities" listed in the Applicability Section, it is not clear how PRC-019 can only apply to TOs that own synchronous condensers because R1 & R2 require GOs to communicate with TOs regarding the generation equipment subject to the standard (units over 20 MVA, units connected at a common bus with total generation over 75 MVA, and blackstart units in the TOPs restoration plan). **The Applicability of TO's is only to those who own synchronous condensers because they have to evaluate the coordination of the protection on this equipment. No change made.** Regarding the "Facilities" listed in the Applicability section, BPA believes that Section 4.2.4 should apply to blackstart units designated as part of a TOP's restoration plan. The phrase "material to and designated as part of" the restoration plan creates ambiguity and would seem to require TOPs & GOs to agree on which generators are "material to" the blackstart plan. **The wording in the Applicability section is directly from NERC's Statement of Registry Criteria. No change made.** R2 is designated as a Long-Term Planning standard, but appears to allow coordination within 90 days following the implementation of setting changes. The phrase "Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1," is not clear. R1 requires coordination at least once every five years. R2 should require coordination before implementation of system, equipment, or setting changes, not within 90 days after. **The intent of the 90 days is to allow the coordination to be evaluated following discovery of a change in limiter or protection settings. The GVSDT anticipates that normally, the evaluation would occur prior to the change. No change made.**
Response: The GVSDT thanks you for your comment. See responses to specific comments above.	
Exelon Corporation and its affiliates	Section D, "Compliance," Part 1.2, "Evidence Retention," (page 4 of 11) first paragraph is unnecessary and redundant since the retention periods specified are for a six year time period which would be the maximum time between compliance audits for a registered entity. Exelon suggests that this paragraph be deleted in its entirety.

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Response: The GVSDT thanks you for your comment. The GVSDT appreciates your position but since a large majority of stakeholders has approved the standard as it is currently written the GVSDT chooses not to modify the wording at this time.	
SMUD	SMUD strongly suggests the SDT align the proposed PRC standard with NERC's current direction of migrating reliability standards to a Results Based Standards (RBS) and internal controls approach. This standard, along with all the other recent NERC PRC proposed standards, are vastly increasing the administrative effort by asking for more documentation of relay settings. For instance, in R1.1.2 - Is it really necessary to have a regulatory requirement for the GO to protect his own generator from damage? (Intentional Space.....)As an alternate approach, why not state that anytime a generator trips off by a protective function that must be set to coordinate with a limiter, the GO must demonstrate that the relay was set per this standard. That is, that the protective function did(emphasis added) coordinate with the limiters. If it is set correctly, there is no violation. If not, violation. This reduces the compliance burden significantly, but does not weaken the incentive to comply. Entities will want to ensure they set their relays per the standard because no one wants to cause an outage or get a violation. But no entity needs to spend time on pre-event, zero-defect, compliance documentation for all its units - only post event documentation is necessary for units that tripped. We feel this type of results based approach is a better choice for this standard.
Response: The GVSDT thanks you for your comment. Future revisions of the standard may be rewritten as RBS. The intent of the standard is to prevent inadvertent tripping due to miscoordination of limiters and protection. The GVSDT agrees that the owner would logically want to protect his own equipment, but this could lead to overprotection.	
Northeast Power Coordinating Council	Suggest the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the Standard and the associated Implementation Plans. Given recent experience with other Standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The Effective Date section refers to percentage of "applicable Facilities". Since "Facility" is a defined term, and MVA is not included in the definition, the GVSDT believes the intent is clear. The GVSDT	

Organization	Question 3 Comment
would prefer to move this standard to recirculation ballot so that the reliability benefits of the standard are achieved sooner rather than make a substantive change that would require another successive ballot.	
New York Power Authority	This Standard does not bring added reliability for the Bulk Electric System; it only adds an administrative burden for the entities. NYPA in its current protection system relay settings process inherently takes into account a margin for a unit's in-service limiters as well as other typical performance parameters.
Response: The GVSDT thanks you for your comment. The GVSDT is operating under the belief that by approving the SAR for this project, industry feels there is a reliability need.	
Utility Services	Utility Services suggests the SDT specifically identify or show examples of how to match the percentage thresholds outlined in the Effective Date sections of the standard and the associated Implementation Plans. Given our recent experience in other standards, it would be helpful for the SDT to establish how the entities can demonstrate meeting the requisite threshold percentages. Over time, we have observed that in some cases, percentages were established by the number of devices or units; but in other cases, the measurement has been based upon magnitude of nameplate ratings.
Response: The GVSDT thanks you for your comment. The Effective Date section refers to percentage of "applicable Facilities". Since "Facility" is a defined term, and MVA is not included in the definition, the GVSDT believes the intent is clear. The GVSDT would prefer to move this standard to recirculation ballot so that the reliability benefits of the standard are achieved sooner rather than make a substantive change that would require another successive ballot.	
PSEG	We voted "Negative" on this standard the reasons shown below:This FIRST COMMENT was provided for MOD-025-1, MOD-026-1, MOD-027-1, and PRC-019-1.1.SYNCHRONOUS CONDENSERS: The GVSDT is not working as a "team" with regards to synchronous condensers owned by TOs. The team working on this standard and PRC-019-1 INSIST that they be included as "applicable facilities," while the team working on MOD-026-1 has stated otherwise. We provided this comment to the MOD-026-1 team in the last set of comments:"The exclusion of synchronous condensers (and other reactive devices) in MOD-026-1 per the rationale provided in the Background (with which we agree)

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	states “Synchronous condensers are not currently addressed in the NERC Registry Criteria” However, companion standards under Project 2007-09 (MOD-025-2 and PRC-019-1) are applicable to synchronous condensers. The GVSDT should address this inconsistency.”The SDT responded as follows:”The SDT believes that MOD-026 is different from the other standards with respect to synchronous condensers due to the complex interaction required between the Transmission Planner and the Generator Owner, and thus believes it better to wait for efforts by others to define where synchronous condensers fit in the functional model.”In response to a similar comment on MOD-025-2 and PRC-019-1, we received these responses:MOD-025-1: “The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in “I5 - Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2.”PRC-019-1: “The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.”We need to see “one” statement from the SDT on the inclusion or exclusion of synchronous condensers that makes sense technically, and soon.2.No reliability benefit has been demonstrated for having the coordination review required by R1 done every five years. We suggest that the R1 be modified so that it’s clear that the entities must “verify” coordination upon the effective date ONLY, but not every 5 years thereafter. The effective date Section 5, part 5.1.1 states “By the first day of the first calendar quarter, two calendar years following applicable regulatory approval each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.” Therefore, we suggest that R1 be rewritten as follows:”BY ITS EFFECTIVE DATE IN SECTION 5, each Generator Owner and Transmission Owner with applicable Facilities shall VERIFY the COORDINATION OF the voltage regulating system controls, (including in-service limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions.”

Response: The GVSDT thanks you for your comment. The verification of coordination required by this standard is closely tied to

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MOD-025 because the reactive capability verification is when miscoordination is more likely to manifest itself. MOD-026, and the other standards in the GV project are not directly linked to PRC-019 and thus have different Applicability and Implementation requirements. The requirement for a five year review is to verify that the limiter settings, protection settings, and machine capabilities have not changed since the last coordination study. If these have not changed, then the study is still valid and documentation that the settings and capabilities have not changed is sufficient.	
Southwest Power Pool Reliability Standards Development Team	We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Response: The GVSDT thanks you for your comment. There is no communication requirement in R2. Presumably, for a planned change, the owner would review the coordination prior to implementing the change. The GVSDT does not feel the present wording creates a reliability gap.	
Omaha Public Power District	We would suggest a revision to R2 to remove following after the 90 days and simply leave it within 90 calendar days of identification or implementation. We would like to know before not after.
Response: The GVSDT thanks you for your comment. There is no communication requirement in R2. Presumably, for a planned change, the owner would review the coordination prior to implementing the change. The GVSDT does not feel the present wording creates a reliability gap.	

END OF REPORT