Consideration of Comments on Generator Verification (PRC-019-1)—Project 2007-09

The Generator Verification drafting team thanks all commenters who submitted comments on the first posting of PRC-019-1, Coordination of Generating Unit/Facility Voltage Regulating Controls with Generating Unit/Facility Capabilities and Protection (Project 2007-09). These standards were posted for a 30-day public comment period from June 15, 2011 through July 15, 2011. The stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 65 sets of comments, including comments from approximately 182 different people from approximately 95 companies representing 9 of the 10 industry segments, as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

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 of Standards and Training, Herb Schrayshuen, at 404-446-2563, or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT posted PRC-019-1 for a 30 day formal comment period from June 15-July 15, 2011. The majority of stakeholders agreed with the proposed standard and provided some comments for revisions to the standard. The Applicability to Transmission Owners was clarified to include only those that own synchronous condenser(s) ad follows:

4.1.2 Transmission Owner that owns synchronous condenser(s)

The GVSDT asked stakeholders if they believed that the proposed PRC-019-1 standard was written to be "technology neutral" such that it can be used for all forms of generation connected to the BES. The vast majority of stakeholders believe that the standard is technology neutral. Several stakeholders that expressed concerns commented that the standard may not work for photovoltaic or wind technologies. The GVSDT agrees that while some of the standard elements might not apply to all technologies, most elements and the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed field current, which would require the excitation system to be in Manual Mode. The GVSDT, having previously considered this and knowing the excitation system to typically be in Auto Mode per VAR-002, provided the following response: The calculation of the SSSL based on a fixed field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

The GVSDT asked stakeholders if they agreed with the applicability to synchronous condensers. The question contained a limit of ≥50 MVA while the standard contained ≥20

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[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

MVA. The GVSDT intended for ≥20 MVA to be the correct number. Many stakeholders pointed out this discrepancy and agreed with the ≥20 MVA threshold. The GVSDT will ask this question again in the next posting.

Some stakeholders suggested higher MVA limits for units applicable to this standard. The GVSDT based the applicability criteria on the current Compliance Registry Criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry Criteria and the BES definition.

Constellation Power pointed out that repeating the Compliance Registry Criteria within the standard is not wise since the standard must be changed if the Compliance Registry Criteria changes. The SDT agrees with this logic but felt it was necessary to include the appropriate Compliance Registry Criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry Criteria. If the Compliance Registry Criteria language for generating units was not included in the standard the standard could be interpreted to apply only to synchronous condensers and not to generators.

Stakeholders were asked if they thought that variable static reactive sources that are not located at generating facilities should be included in the standard. The vast majority of stakeholders did not see a reliability need for including variable static reactive sources that are not located at generating facilities. This equipment is normally protected for internal failures and do not have similar equipment protection such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static reactive resources not located at generating facilities are outside the scope of this project. For these reasons, including static reactive resources not located at a generating facility are not part of this standard.

The majority of stakeholders agreed with the Purpose Statement of PRC-019-1. The GVSDT revised the Purpose Statement of the standard for clarity based on stakeholder comments. The revised Purpose Statement is:

> To improve the reliability of the Bulk Electric System by ensuring coordination of generating unit/facility or synchronous condenser voltage regulating controls and limit functions with generator capabilities and protection system settings.

The proposed effective dates provide a “phased-in” approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/facilities. The majority of stakeholders agreed with the phased in approach. Stakeholders pointed out that, for jurisdictions where regulatory approval is not required, the 100% completion item was missing. The GVSDT added item 5.2.5:

> 5.2.5 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable units.

Stakeholders were asked about Section G of the standard which provides examples of how the coordination can be demonstrated. The majority of stakeholders agreed with the information provide and several stakeholders made suggestion for clarifying language. Specific changes were made to Section G of the standard based on comments received. These changes included:

1. The example diagrams added that they are drawn at nominal voltage and frequency.

2. The formula for calculating the radius of the SSSL was corrected.

3. The items “under-excited limiters or minimum excitation limiters” and “over-excited limiters or maximum excitation limiters” have been placed in the bulleted list of the standard.

4. The SDT changed “protective” to “protection” within the standard to be consistent with Section G.

5. The SDT added a reference document for use in calculation of SSSL.

Several commentators were concerned that Section G has a method for illustrating coordination of AVR limiter/protection functions with other protection systems. The SDT agrees that there are numerous ways of demonstrating coordination and does not prescribe any particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT reviewed the requests to remove the distance relay and volts/hertz relay elements from the standard. It is the belief that these two elements remain in the document since a) the distance element should illustrate coordination with field forcing controls of the AVR, and b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

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	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
2.	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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity 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.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5

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
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
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
3.	Group	Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Marcela Caballero	IID	WECC	5
5.	Cathy Bretz	IID	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Albert DiCaprio	IRC Standards Review Committee (joint comments)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Ben Li	IESO	NPCC	2
4.	Mark Thompson	AESO	WECC	2
5.	Steve Myers	ERCOT	ERCOT	2

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3
2.	Alivan Depew	Pepco Holdings Inc	RFC	1, 3

6.	Group	Jonathan Sykes, Chair	NERC System Protection and Control Subcommittee	X			X	X					X

No additional members listed.

7.	Group	Carol Gerou	Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Power Dist	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Copperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
10.	Joseph DePoorter	Madison Gas and Electric Company	MRO	3, 4, 5, 6
11.	Scott Nichols	Rochester Public Utilities	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative	MRO	1, 3, 5, 6
14.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
15.	Scott Bos	Muscatine Power and Water	MRO	3, 4, 5, 6
16.	Lee Kittleson	Otter Tail Power Company	MRO	5, 1, 3, 6

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

17. Marie Knox	Midwest ISO	MRO	2

				1	2	3	4	5	6	7	8	9	10
8.	Group	Jonathan Hayes	SPP Reliability Standards Development Team										

Additional Member	Additional Organization	Region	Segment Selection
1. Paul Reynolds	Sunflower Electric Power Corporation	SPP	1
2. Valerie Pinamonti	AEP	SPP	1, 3, 5
3. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4. Clem Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
5. Louis Guidry	CLECO	SPP	1, 3, 5
6. Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
7. Robert Rhodes	SPP	SPP	2

				1	2	3	4	5	6	7	8	9	10
9.	Group	Charles W. Long	SERC Planning Standards Subcommittee	X									X

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren Services Co.	SERC	1
2. James Manning	NC Electric Membership Corp.	SERC	1
3. Philip Kleckley	SC Electric & Gas Co.	SERC	1
4. Pat Huntley	SERC Reliability Corp.	SERC	10
5. Bob Jones	Southern Company Services	SERC	1

				1	2	3	4	5	6	7	8	9	10
10.	Group	Tim Brown	Idaho Power-Power Production					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Guy Colpron	Idaho Power	WECC	5
2. Mark Pfeifer	Idaho Power	WECC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. S. T. Abrams	Santee Cooper	SERC	1
2. Phil Pierce	Santee Cooper	SERC	5

Additional Member	Additional Organization	Region	Segment Selection
3. Paul Camilletti	Santee Cooper	SERC	5
4. Rene Free	Santee Cooper		1
5. Tom Curtis	Santee Cooper	SERC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Annette Bannon	PPL Generation					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
3.		PPL Brunner Island, LLC	RFC	5
4.		PPL Holtwood, LLC	RFC	5
5.		PPL Martins Creek, LLC	RFC	5
6.		PPL Montour, LLC	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		MRO	5, 6
2.	Connie Lowe		SERC	5, 6
3.	Michael Gildea		RFC	5, 6
4.	Larry Whanger		SERC	5
5.	Mike Crowley		SERC	1, 3
6.	Jeff Bailey		MRO	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Baznik	FE	RFC	1
2.	Bill Duge	FE	RFC	5
3.	Brian Orians	FE	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Joe Spencer - SERC Bob Jones - DRS chair	SERC Dynamics Review Sub-committee										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.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Mallory Huggins	NERC Staff										

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ken Brown	PSE&G	RFC	1, 3
2.	Clint Bogan	PSEG Fossil	RFC	5
3.	Peter Dolan	PSEG ER&T	RFC	6
4.	Scott Slickers	PSEG Fossil	NPCC	5
5.	Eric Schmidt	PSEG ER&T	NPCC	6
6.	Mikhail Falkovich	PSEG Fossil	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Joe Spencer - SERC staff	SERC Generation sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robin Wells - vice chair	LG&E/KU	SERC	
2.	Kumar Mani	Progress Energy	SERC	
3.	Bill Shultz	Southern Co.	SERC	
4.	Tom Higgins	Southern Co.	SERC	
5.	Brad Haralson	AECI	SERC	
6.	Terry Crawley	Southern Co.	SERC	
7.	Chris Georgeson - chair	Progress Energy	SERC	
8.	Tracey Stubbs	Entergy	SERC	
9.	Paul Palmer	TVA	SERC	
10.	David Thompson	TVA	SERC	
11.	Jules Guillot	Entergy	SERC	
12.	Matt Wallace	Ameren	SERC	
13.	Joe Spencer	SERC Reliability Corp.	SERC	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Group	Jason Marshall	ACES Power Members						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
20.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
21.	Individual	Bo Jones	Westar Energy	X		X		X	X				
22.	Individual	Antonio Grayson	Southern Company					X					
23.	Individual	David Thompson	Tennessee Valley Authority GO					X					
24.	Individual	David Youngblood	Luminant Power					X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
25.	Individual	David Miller	Lakeland Electric	X									
26.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
29.	Individual	Edward Cambridge	APS	X		X		X					
30.	Individual	Brad Haralson	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
32.	Individual	Greg Campoli	New York Independent System Operator		X								
33.	Individual	Samuel Reed	Tri-State Generation and Transmission, In.	X				X					
34.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
35.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
36.	Individual	Mace Hunter	Lakeland Electric	X		X		X					
37.	Individual	John Bee	Exelon	X		X		X					
38.	Individual	Michael Goggin	American Wind Energy Association								X		
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Bob Casey	Georgia Transmission Corporation	X									
41.	Individual	Jeanie Doty	Austin Energy					X					
42.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
43.	Individual	Michael Brytowski	Great River Energy	X		X		X					
44.	Individual	Vladimir Stanisic	BC Hydro	X	X	X		X					
45.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
46.	Individual	Amir Hammad	Constellation Power Generation					X					
47.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
48.	Individual	Thad Ness	American Electric Power	X		X		X	X				
49.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
50.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
51.	Individual	Gary Chmiel	GE Energy										
52.	Individual	Kathleen Goodman	ISO New England		X								
53.	Individual	Dan Hansen	GenOn Energy					X					
54.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
56.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
57.	Individual	Jose H Escamilla	CPS Energy			X							
58.	Individual	Michael Falvo	Independent Electricity System Operator		X								
59.	Individual	Karen Alford	Gainesville Regional Utilities	X		X		X					
60.	Individual	Kirit Shah	Ameren	X		X		X	X				
61.	Individual	Rex Roehl	Indeck Energy Services					X					
62.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
63.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
64.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
65.	Individual	John Yale	Chelan County PUD	X				X	X				

1. **Do you agree that the standard, as written, is "technology neutral," such that it can be used for all forms of generation connected to the BES? If you do not agree, please state your reasons and suggest alternatives to make the standard technology neutral in the Comment area.**

Summary Consideration: The majority consensus of the stakeholders was "yes," the standard is technology neutral. Several of the "no" responders commented that the standard may not work for photovoltaic or wind technologies. The SDT agrees that while some of the standard elements might not apply to all technologies, most elements and the example diagrams (in general) would apply to all technologies.

One stakeholder recognized that the SSSL calculation plot used in the example diagrams is based on a fixed field current, which would require the excitation system to be in manual mode. The SDT, having previously considered this and knowing the excitation system to typically be in auto mode per VAR-002, provided the following; the calculation of the SSSL based on a fixed-field current value is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex.

Organization	Yes or No	Question 1 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		

Organization	Yes or No	Question 1 Comment
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric	Yes	

Organization	Yes or No	Question 1 Comment
Cooperative, Inc.		
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD		Cowlitz has no opinion.
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (top of page 7) states "(F)or the coordination required by this standard, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current." This conflicts with Requirement R1.1.1 that states "... assuming normal AVR control loop and system steady state operating conditions. Currently the two statements are in conflict with one another in that one requires a "fixed" field current (i.e., AVR in "manual") and the other requires "normal operation" (i.e., AVR in "automatic").The SDT needs to allow for automatic mode for AVR to accommodate those Generators that have redundant automatic channels as is the case for newer digital AVRs. This will allow the owner to use AVRs automatic mode when plotting SSSL.
Response: Thank you for your comment. The SDT agrees that the generators must normally operate in AVR mode. The calculation of the SSSL, based on a fixed-field current value, is a typical industry practice and provides a conservative number to be used for coordination purposes without making calculations overly complex. The SSSL is an element that applies only to synchronous generating units. It would not necessarily apply to wind or solar facilities.		
American Wind Energy	Yes	

Organization	Yes or No	Question 1 Comment
Association		
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	This draft standard appears to have been written from a traditional steam or combustion turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the compliance registry change.
Response: Thank you for your comment. Because this standard includes equipment that is not specifically listed in the Registry criteria (synchronous condensers), the SDT feels it is necessary to explicitly list the generating equipment included in the criteria. If the Registry criteria are revised in the future, this standard may have to be revised as well.		
Consolidated Edison Co. of	No	This draft standard appears to have been written from a traditional steam or combustion

Organization	Yes or No	Question 1 Comment
NY, Inc.		turbine generator perspective. It may not work for a photovoltaic or wind generator installation.
Response: Thank you for your comment. The SDT received input from owners and operators of wind and solar Facilities, as well as an OEM involved with these technologies. The examples provided contain some elements that may not apply to all technologies; though the diagrams, in general, would apply to all technologies.		
American Electric Power	Yes	Though we agree that the standard as written is "technology neutral", its apparent neutrality might well be impacted by the definition of BES which is currently being revised. This topic might need to be revisited once the revised definition of BES has been approved.
Response: Thank you for your comment. If the definition of the BES is revised in the future, this standard may have to be revised as well.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP's gas and steam turbine units use voltage limiting and protection system technologies which are clearly referenced under PRC-019-1.
Response: Thank you for your comment.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	No	See response to Question #2 below.
Lincoln Electric System		
CPS Energy		

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

2. The SDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated equal to or greater than 50 MVA. The standard applies to generating units/Facilities that meet the Compliance Registry criteria and to synchronous condensers rated 50 MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the Comment section.

Summary Consideration: The majority of stakeholders agreed with the applicability of the standard.

Several stakeholders noted that the posted question mistakenly stated that the proposed standard applied synchronous condensers rated equal to or greater than 50 MVA, rather than the correct value of equal to or greater than 20 MVA. Four of the "no" votes were based on disagreeing with the 50 MVA threshold, and preferring the (correct) 20 MVA threshold.

A few stakeholders recommended applying the standard to units that are larger than 75 MVA, and pointed out that this is the threshold used in the current draft definition of the BES. Three more stakeholders also recommended a higher threshold. The SDT based the applicability criteria on the current Compliance Registry criteria and the current posted draft of the BES definition, both of which currently set the applicability threshold at 20 MVA for individual units. The SDT felt that there was not sufficient technical justification to set the applicability requirement at a value that differs from the Compliance Registry criteria and the BES definition. If the Compliance Registry criteria and/or the BES definition changes in the future, it is likely that the applicability for this standard should be changed as well.

Constellation Power pointed out that repeating the Compliance Registry criteria within the standard is not wise since the standard must be changed if the Compliance Registry criteria changes. The SDT agrees with this logic, but felt it was necessary to include the appropriate Compliance Registry criteria within the standard because the standard also applies to synchronous condensers, which are not explicitly mentioned in the Compliance Registry criteria. If the Compliance Registry criteria language for generating units was not included in the standard, the standard could be interpreted to apply only to synchronous condensers, and not to generators.

A couple of stakeholders stated that the standard should not apply to synchronous condensers because they are not included in the Compliance Registry. The SDT feels, as do many other stakeholders, that, for reliability reasons, this standard needs to apply to synchronous condensers, and it is appropriate to list equipment that is not in the Registry criteria.

Organization	Yes or No	Question 2 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	Question #2 mentions that a threshold was chosen by the SDT for synchronous generators greater than, or equal to, 50MVA. However, the existing language in Section A- 4.2.1 of the standard makes it applicable to both individual generating units and synchronous condensers greater than 20MVA. The 50MVA threshold for synchronous condensers seems reasonable, so if this was the intent then the language in the standard should be revised.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
NERC System Protection and Control Subcommittee	No	The SPCS notes that the posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. The SPCS agrees with the 20 MVA threshold in the posted standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	

Organization	Yes or No	Question 2 Comment
SPP Reliability Standards Development Team	Yes	This question refers to the applicability of the standard yet doesn't reflect the wording in this question. In the standard the applicability for synchronous condensers is 20 MVA due to it being lumped with single units. This needs to be broken out in the applicability section of the standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	No	See item 1 in Question 9 Response.
Dominion	Yes	
FirstEnergy	Yes	Although we agree with the applicability, the standard that was posted does not mention the 50 MVA threshold.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	The posted standard references synchronous condensers rated 20 MVA in Applicability section 4.2.1. We agree with the 20 MVA threshold in the posted standard.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group	No	The question and the standard contradict each other. The standard states that it applies to “synchronous condensers > 20 MVA” not “rated > 50 MVA.We do not agree with the threshold MVA applicability for generators. Field testing and industry history do not warrant the need for such a low MVA threshold. We suggest that the threshold be for larger units (rated > 500 MVA) that have the ability to significantly impact BES reliability. The resources required to apply this standard to smaller units compares to the benefits to the BES and the GO are generally not justified in most regions. However, it can be argued that smaller units can have a significant impact on the BES, especially in weak systems. Therefore, we recommend that an inclusion criteria be developed that would require units in such regions to be included.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	In the standard the applicability for synchronous condensers is > 20 MVA for an individual unit. Additional language should be added to the standard to address the applicability for generating units/facilities.
Response: Thank you for your comment. The SDT believes that Section 4.2.1 does address the applicability for generating units/Facilities.		
Southern Company	No	We feel that this standard is not applicable for solar facilities. For other facilities, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA

Organization	Yes or No	Question 2 Comment
		in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units â ‰ ¤ 75MVA may be identified by a transmission entity as critical for BES reliability. Thus, the standard could include requirements applicable to such units where identified by a tranmission entity as critical for BES reliability.
Response: Thank you for your comment. Miscoordination between inverter capabilities and protection would apply to solar facilities. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		

Organization	Yes or No	Question 2 Comment
Tri-State Generation and Transmission, In.	Yes	The standard seems to indicate 20mva instead of the stated 50mva.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Cowlitz County PUD	No	The Compliance Registry Criteria was hastily put together without proper reliability justification. The end result has created a registration process that assumes reliability impact where there is none, and allows exemptions where reliability impact does exist. Cowlitz believes in a protective backbone approach to reliability, the bulk power system (BPS) as a whole need not be completely protected in order to assure its reliability. There exists a core “backbone” subset from the BPS which must be protected; this is known as the Bulk Electric System (BES) and is currently undergoing revision in Project 2010-17. Once this project is complete, it may be necessary to revise the Compliance Registry Criteria to clearly identify entities as users of the BES who must participate in BES protective standard compliance activities. In other words, the Compliance Registry objective should be to identify all entities who must participate in the protection of the BES to assure reliability of the BPS, not identify elements of the BES. Using the Compliance Registry Criteria’s generator MVA name plate ratings to assign applicability of the Standard is questionable. Cowlitz can find no reliability justification; it appears to be completely arbitrary. If models are currently accurate it should be a simple process to verify the size of generation that can be ignored. Further, the unit versus plant MVA criteria is illogical. If the BES can withstand the loss of a 75 MVA plant, then logically it will withstand the loss of a 20 MVA unit. Cowlitz believes that after the appropriate study is completed, the applicability line should be somewhere in the range of a verified nominal plant or unit output of 100 to 200 MVA. Last of all, applicability should be assigned to BES generation when it has been defined.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units. The GVSDT is not attempting to justify the NERC registration criteria through this standard. We are simply using it as the basis for Facility applicability.		
Xcel Energy	Yes	There is a discrepancy between the question and the 20 MVA size limit for synchronous condensers in the draft standard. We believe 50 MVA is the better value.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not		

Organization	Yes or No	Question 2 Comment
mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Lakeland Electric		
Exelon		
American Wind Energy Association	Yes	
Tacoma Power		
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro		
Northeast Utilities	No	Generally only units larger 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
Constellation Power Generation	No	Although CPG agrees with the approach of applying this standard to all generation facilities in the compliance registry, mimicking it in the standard is redundant and problematic. Should the compliance registry change, then this standard may include facilities not registered with NERC. Conversely, this standard could potentially exclude facilities in the registry should the

Organization	Yes or No	Question 2 Comment
		compliance registry change.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Consolidated Edison Co. of NY, Inc.	No	Generally only units larger than 75 MVA are impactful. Recommend making 75 MVA the reporting floor [regardless of connected voltage]. This is consistent with the current draft BES definition being prepared by the BES SDT.
Response: Thank you for your comment. The proposed draft of the BES definition that is posted on the NERC website includes individual units of 20 MVA and greater, not 75 MVA. If the draft changes in the future, this standard and others may need to be revised.		
American Electric Power	No	It needs to be explicitly stated whether or not a Transmission Owner is held under R1 if they do not own synchronous condensers. This might be achieved by adding additional language to 4.1.2 stating that the standard applies to those who own facilities as specified in 4.2.Usage of the words “coordinate” and “coordination” seems ambiguous, and might be open to interpretation. In other standards these words are often used to describe communication between NERC functions rather than ensuring that necessary and sufficient settings exist among equipment types to permit them to operate in a pre-determined sequence.The threshold of 50MVA is not mentioned in the draft standard. Rather, 4.2.1 specifies a threshold of 20MVA.It appears the term “synchronous condenser” has been omitted from R1. Suggest using "Each Generator Owner and Transmission Owner with applicable Facilities shall coordinate its generating unit, generating Facility, or synchronous condenser voltage regulating system controls, including limiters and protection functions with the generating unit and Facility or synchronous condenser capabilities and protective system settings; to include as applicable".
Response: Thank you for your comment. The Applicability section of the draft standard has been changed to explicitly show that the standard only applies to TOs that own synchronous condensers. The concept of “coordination,” as applied to protective relays, limiters, and equipment capabilities, is commonly understood in the industry as meaning their desired sequence of operation. The value of 50 MVA was mistakenly used in the question on this form. The SDT agrees with your suggested wording revision to R1. The SDT also agrees that the Application section needed to be clarified for TOs, and has modified Section 4.1.2 to state that the standard only applies to TOs that own synchronous condensers.		
Ingleside Cogeneration LP	No	PRC-019-1 is appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be

Organization	Yes or No	Question 2 Comment
		not be considered applicable to any NERC standard at this time. There is a project team presently modifying the definition of the Bulk Electric System - this determination should rest with them.
Response: Thank you for your comment. For reliability reasons, this standard needs to apply to synchronous condensers, and it is appropriate to list equipment that is not in the Registry criteria. Many elements of the Bulk Electric System are not specifically named in the Registry criteria or definition of the BES. For example, PRC-005 deals with Protection Systems, which are not specifically named in the BES definition or the Registry criteria.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England	Yes	Yes, however the standard should not rewrite the Compliance Registry as attempted. The registry language of section IIIc.3 and IIIc.4 is more precise and differs from what is proposed in the standard. For instance, the registry's wording on Black Start generators applies to a blackstart unit material to and designated as part of a transmission operator entity's restoration plan. If the NERC standards become effective for non-material 9 MVA black start units those units will likely drop out of the program. All that is needed is to have the standard applicable to Generator Owners and let the Registry dictate those who must register and comply.
Response: Thank you for your comment. The SDT agrees to use the wording in the current version of the Registry criteria. Because this standard includes equipment that is not specifically listed in the Registry criteria (synchronous condensers), the SDT feels it is necessary to explicitly list the generating equipment included in the Criteria. If the Registry criteria are revised in the future, this standard may have to be revised as well.		
GenOn Energy		
Manitoba Hydro	No	The 50MVA criteria in question 2 does not appear in the draft standard. If the question is valid and 50MVA is not a typo, it is not clear why the size of applicable synchronous condensers should be different from that of synchronous generators. Also 50 MVA seems like an arbitrary number with no basis. MH proposes that the applicable MVA rating of synchronous generators and synchronous condensers be identical. This eliminates confusion associated with units capable of operating in either mode.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Duke Energy	No	We feel that this standard is not applicable for solar facilities or induction type generators used in some wind farms. Several different exemption criteria are specified in the various GVSDT standards. We understand the distinction made for MOD-26/27 (100MVA) from the MOD-25 criteria (75MVA). The standard likely should be consistent with one or the other, rather than having a 3rd criteria (50MVA). For this standard, we recommend that only units > 75MVA be included. If the significant aggregated plant MVA size is > 75 MVA, then an individual unit included as significant should also be 75 MVA. Consider the case where a 21 MVA machine would be included in the scope, yet a 'five unit, 15 MVA each' plant (totaling 75 MVA) would be excluded. A 20MVA machine today can not impact the system like it could have 20 years ago. A technical basis for including units as small as 20MVA in all regions needs to be provided. NERC is focusing on standard requirements that have significant impacts on system reliability, and including units less than 75MVA seems to be inconsistent with this philosophy. We do acknowledge that in some areas of the BES, some units â‰¤ 75MVA may be identified by a transmission entity as critical for BES reliability. Regional criteria are allowed to address these concerns to make requirements applicable to such units identified as critical for BES reliability in that region.
Response: Thank you for your comment. Miscoordination between inverter capabilities and protection would apply to solar Facilities. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	There is no technical justification provided to support the 50 MVA criterion. Absent this, we propose to use the 20 MVA for generators as a general criterion for synchronous condensers as well.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA.		
Gainesville Regional Utilities	Yes	

Organization	Yes or No	Question 2 Comment
Ameren	Yes	
Indeck Energy Services	No	Not sync condensers
Response: Thank you for your comment. The SDT believes that synchronous condensers are as important a Reactive resource as synchronous generators and should be included as applicable equipment in this standard.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	IMPA supports the application of the standard to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 50MVA and greater.
Response: Thank you for your comment. The question on this form mistakenly used the value of 50 MVA. Although synchronous condensers are not mentioned in the Registry criteria, the SDT feels that the 20 MVA value more nearly matches the value for individual generating units.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

3. As currently drafted, this standard applies to synchronous generators, synchronous condensers, and variable static Reactive resources located at asynchronous generating Facilities (e.g., wind and solar sites). Do you see a reliability need for including variable static Reactive resources (e.g., static VAr compensators) that are not located at generating sites in this standard? Please explain your answer in the comments block.

Summary Consideration: —The majority of stakeholders did not see a reliability need for including variable static Reactive sources that are not located at generating Facilities. This equipment is normally protected for internal failures and do not have similar equipment protection, such as synchronous generators using generator field limiters and over- and under-excitation protection. The SDT has determined that variable static Reactive resources not located at generating Facilities are outside the scope of this project. For these reasons, the drafting team has not included static Reactive resources not located at a generating Facility.

Organization	Yes or No	Question 3 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Imperial Irrigation District (IID)	No	These devices are covered already under the VAR standards.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	No	Question #3 indicated that as currently drafted the standard applies to variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites). This is either specifically mentioned, or inferred, within the language of the June 15, 2011 Draft 2 standard. Regarding the question of a reliability need for including variable static reactive resources (e.g. static Var compensators) that are not located at generating sites in this standard, the answer is no. We see no need to make the standard applicable to Static Var Compensators (SVC's), whether they are located at generating sites, or remote from generating sites. An SVC is merely a thyristor switched / controlled capacitor or reactor. Maximum and minimum output is controlled by the firing controls to the thyristor, and is limited by the size of the installed shunt capacitor / reactor banks. When the thyristor is switched off there is no output. As the firing angle is increased toward the full on position the reactive output is increased until the full value of the shunt capacitor bank, or reactor bank, is reached. Protective devices and settings on the shunt capacitor bank and reactor bank within the SVC are typical of those employed on fixed banks. The control system merely provides a means to adjust the output between zero and full bank rating. As in the case of fixed banks, SVC protective devices are set assuming the full bank is in service. Therefore, if fixed shunt reactive banks are not subject to the standard, which they should not be, then SVC's should not be either. Synchronous machines, however, are a different story entirely. The quantity of reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition the unit may loose synchronism, or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and / or terminal overvoltage caused by over-excitation of the field can result in equipment damage, or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices.
Response: Thank you for your detailed comment. While SVC's located at the bus of a variable energy resource would not coordinate with the individual generating equipment, the internal coordination between the current limiters and the protection of the SVC can be verified.		
NERC System Protection and	Yes	Devices such as Static Var Compensators and STATCOMs have equipment limitations, control

Organization	Yes or No	Question 3 Comment
Control Subcommittee		systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	
SPP Reliability Standards Development Team	Yes	We weren't able to locate the variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites) within the standard as the question suggests. We feel like variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites should have been included but would request that the team provide a limit on the size of these types of facilities. Our team isn't sure what a cutoff number would be, but would ask that the drafting team investigate this issue to come up with an appropriate number.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities, such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production		
Santee Cooper		
PPL Generation	No	

Organization	Yes or No	Question 3 Comment
Dominion	No	
FirstEnergy	No	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	Devices such as static var compensators (SVCs) and static compensators (STATCOMs) have equipment limitations, control systems, and protections that must be coordinated to assure system reliability. The reliability impact of unnecessarily tripping reactive support from a variable static resource is similar to tripping reactive support from a generator or synchronous condenser.Also, the standard must remain neutral as to the type of reactive resource, allowing for other technologies such as storage and demand-side regulation through electronically coupled loads that are relied upon for reliability purposes in the same vain as other reactive sources cited.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Public Service Enterprise Group	No	First, the inclusion of "variable static reactive resources located at asynchronous generating facilities (e.g. wind and solar sites)" was not noted in the standard. Second, we do not believe that including other static reactive resources that are not located at generating sites would materially impact reliability
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls.. This equipment could include static Reactive resources (typically at asynchronous Facilities, such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
SERC Generation sub-committee		
ACES Power Members	No	It is not clear how this standard is applicable to variable static reactive resources located at asynchronous generating facilities. They do not appear in applicability section.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Arizona Public Service Company	No	
Westar Energy	Yes	Currently the requirements do not address variable static reactive resources located at asynchronous generating facilities as the question states. If the intent is for the standard to apply to variable static reactive resources located at asynchronous generating facilities, we propose language be added to the standard to address these resources. Yes, we do see a reliability need for including variable static reactive resources (e.g. static VAr compensators) that are not located at generating sites. We propose that language be included to address the limit on the size of these types of facilities.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Southern Company		
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	Yes	

Organization	Yes or No	Question 3 Comment
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.		
Dynegy Inc.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	The standard name indicates it applies to generating sites.
Response: Thank you for your comment.		
Cowlitz County PUD	Yes	But not at the 20/75 MVA name plate criteria. First the applicability should be tied to expected maximum MVA output. Second, the MVA basis should be established from a modeling study. Ultimately, the applicability should only include plants that are members of the BES once this has been defined.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Xcel Energy	No	These units are not tested under the proposed MOD-025-2, so should not be included in PRC-019-1.
Response: Thank you for your comment.		
Lakeland Electric		

Organization	Yes or No	Question 3 Comment
Exelon	No	Exelon does not see a reliability need to include static reactive resources in PRC-019. The standard as written is applicable to voltage regulating controls and limit functions with generator capabilities and protection system settings which is generator specific. Adding static reactive resources would require unnecessary additional guidance to be included in the standard. The maintenance and coordination of relays related to static reactive resources is currently covered in PRC-005 and modeling and studies are included in the MOD standard.
Response: Thank you for your comment.		
American Wind Energy Association	No	
Tacoma Power	No	Even if the variable devices or their impact is well defined, such as “Devices within 2 buses and that can affect the transmission system voltage plus or minus 5% or greater”, including this requirement for variable static reactive sources could involve a wide scope of devices and potentially many owners and operators for very little improvement in reliability.
Response: Thank you for your comment.		
Georgia Transmission Corporation		
Austin Energy		
Wisconsin Electric	No	The primary applicability should be to rotating synchronous machines which must have their protection settings and excitation controls properly coordinated with the machine capability. It is not clear how this can be applied to wind generators.
Response: Thank you for your comment. The standard describes “generating Facility voltage regulating controls.” This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT agrees that static Reactive resources not at generating Facilities should not be within the scope of this standard.		
Great River Energy		

Organization	Yes or No	Question 3 Comment
BC Hydro	No	
Northeast Utilities	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	Yes	Only units larger 75 MVA are generally impactful. We recommend making 75 MVA the reporting floor [regardless of connected voltage].Coordination will be needed. Static VAR Compensators are typically self protected by the vendor. As long as the interface point (transformer) is properly and redundantly protected and the Static VAR Compensator safely shuts down for internal faults or out of spec operation, there should be minimal need for coordination with transmission system protection. However, this issue would have to be researched with the vendor of the equipment. Coordination with the Transmission Operator will have to be reviewed for pre and post protection system operation conditions.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
American Electric Power	No	AEP sees no benefit to the reliability of the BES in adding to this standard the controls associated with static reactive resources.
Response: Thank you for your comment.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP is hesitant to require validation of components which have not been clearly identified as a reliability imperative under either the revised definition of the BES or CIP-002-4's bright-line criteria.
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	No	Static VAr compensators do not belong in a generation standard.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar). The SDT agrees that static Reactive resources not at generating Facilities should not be within the scope of this standard.		
Duke Energy	No	See the purpose of the standard. It's not clear why a generation protection/control coordination requirement would be applicable to non-generation resources, other than maybe synchronous condensors.
Response: Thank you for your comment. The standard describes "generating Facility voltage regulating controls." This equipment could include static Reactive resources (typically at asynchronous Facilities such as wind or solar).		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts. Further, SVCs do not "trip", per se, they vary their reactive outputs including going to and crossing 0 MVar and hence some

Organization	Yes or No	Question 3 Comment
		of the interactions between the device and its protection systems in the case of generators/synchronous condensers are not applicable to SVCs.
Response: Thank you for your detailed comment.		
Gainesville Regional Utilities	No	
Ameren	Yes	Question should be directed at transmission planners. I would believe the static VAr compensators are required for system voltage support, similar to synchronous condenser or generation.
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		
Indeck Energy Services	No	Not registered
Response: Thank you for your comment.		
Oncor Electric Delivery Company LLC	No	Oncor does not believe that there is a reliability need for including dynamic or static reactive resources (e.g. static VAr compensators) that are not located at generating sites in this standard.
Response: Thank you for your comment.		
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	If there is a reliabiity need for synch-condensors and generators, why not SVCs for similar minimum capacity? don't they similarly impact system reliability?
Response: Thank you for your comment. The standard applies to voltage control resources at generating Facilities, regardless of their design. The		

Organization	Yes or No	Question 3 Comment
SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard.		

4. **The SDT revised the Purpose of the standard in accordance with the SAR, "To improve the reliability of the Bulk Electric System by preventing tripping of generating units/Facilities due to miscoordination of generating unit/Facility voltage regulating controls, and limit functions with generator capabilities and Protection System settings."**

   Do you agree with the revised Purpose of the standard? If not, please provide suggested language changes in the Comment section.

Summary Consideration: The vast majority of stakeholders agreed with the revised Purpose of the standard. Topics of concern among those not in agreement included the following (# of stakeholders expressing the concern listed in parenthesis):

- **Concern that existing language limits the standard only to traditional rotating machinery.**
- **Concern that "capability" was inconsistently used.**
- **Concern that units less than 50 MVA are too small to include.**
- **Dislike "prevent tripping," suggest "reduce the potential for tripping."**
- **Concern that PRC-001 should include this standard's scope.**
- **Dislike the use of "Protection System settings."**
- **Concern that Purpose over reaches the purpose and intention of the SAR.**

The drafting team made minor changes to the Purpose in response to the concerns and suggestions provided by the stakeholders. The proposed Purpose is:

> **To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.**

Organization	Yes or No	Question 4 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		Does this SDT really believe a standard will "prevent" trippings due to mis-coordination?
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		

Organization	Yes or No	Question 4 Comment
PPL Generation	No	As stated in comment 2 for item 9 below, NERC is not being consistent in using the term "capability." It refers in other standards to that which can be achieved, not to the condition at which tripping is needed.
Response: Thank you for your comment. The intent of the standard, including the wording in the Purpose statement, is that the equipment capability be considered in the overall coordination study. Requirement R1, part 1.1.1, has been revised to clarify that protection should protect the equipment.		
Dominion	Yes	
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	Verification on unites less than 50 MVA is unnecessary burden and does not add significantly to reliability of BES. Many of these units are not even modeled because of the availability of other units for a given schedule.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Westar Energy	Yes	

Organization	Yes or No	Question 4 Comment
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	
Lakeland Electric		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	

Organization	Yes or No	Question 4 Comment
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	No	Replace the phrase "...preventing tripping..." with "...reducing the potential for tripping..."
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
Constellation Power Generation	No	Although CPG believes that the purpose of this standard is valid and accurate, it closely resembles the purpose of PRC-001 and therefore the requirements drafted in PRC-19 should be rolled into a revision of PRC-1.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The PRC-001 SDT could propose retiring PRC-019-1 as part of their process if they include the content of PRC-019 in their standard.		
Consolidated Edison Co. of NY, Inc.	No	Modify the wording to reflect all 'real and reactive power sources,' not limiting it exclusively to traditional rotating machinery.
Response: Thank you for your comment. The SDT does not agree with the expansion in scope that would result from the suggested change in wording. For example, this would include all transmission capacitor banks on the BES. The scope of this standard is not limited to traditional rotating machinery, but also applies to all generating Facilities, including asynchronous Facilities such as wind and solar.		
American Electric Power	No	We are concerned by the inclusion of "protection system settings" in how it might differ from, or be confused with, the NERC defined term Protection System. The term "generator capabilities" should be removed from the purpose statement (as well as the requirements), as it is general enough of a term to make proving compliance difficult.
Response: Thank you for your comment. The "Protection System settings" are the settings used in the Protection System. For the purpose of this standard, some of the functions of the Generator Protection System may be among those that need to coordinate with limiters and equipment capabilities. The SDT feels it is appropriate to consider both "Protection System settings" and "generator capabilities." Documentation of "generator capabilities" are usually provided by the OEM, but may be modified by the Generator Owner for specific conditions.		
Ingleside Cogeneration LP	Yes	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy	No	Disagree strongly: It is overreach to make this a generator protection standard; the standard is not comprehensive enough to take on that task. As a result, the SDT has overstated the purpose and intent of this standard. Simple is better and appropriate. Purpose: To improve reliability through coordination of generator protection systems with unit/facility voltage

Organization	Yes or No	Question 4 Comment
		regulating limiter functions and protection.
Response: Thank you for your comment. The SDT agrees with your concern, and has changed the wording to that suggested by the Independent Electricity System Operator.		
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	Yes	We do not have any real issues with the purpose statement; however, we offer an alternative to add a bit more positive spin (as opposed to preventing tripping):To improve the reliability of the Bulk Electric System by ensuring proper coordination of generating unit/facility voltage regulating controls and limit functions with generator capabilities and protection system settings.
Response: Thank you for your comment. The SDT agrees, and has revised the language based on your proposed wording for the Purpose statement.		
Gainesville Regional Utilities	Yes	
Ameren	Yes	
Indeck Energy Services	No	There is no evidence that this needs to be done to any unit less than the NERC Reportable Disturbance level for the control area.
Response: Thank you for your comment. The SDT based the applicability of the standard on the Registry criteria, and does not have sufficient technological justification to deviate from those values.		
Oncor Electric Delivery Company LLC	Yes	

Organization	Yes or No	Question 4 Comment
Indiana Municipal Power Agency	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

5. The proposed effective dates provide a "phased-in" approach to establishing compliance with this standard to provide adequate time for entities to include all applicable units/Facilities. Do you agree with the proposed implementation schedule? If not, please provide an alternative implementation schedule, approach, and supporting information in the comments.

Summary Consideration: A majority of stakeholders agreed with the proposed phased-in approach outlined in the implementation schedule. Topics of concern among those not in agreement included the following:

- **Concern that Applicability Section 5.2.5 is missing.**
- **Suggestion that the first 20 percent be due in two years vs. one year.**
- **Concern over M1 previous test evidence requirements.**
- **Conflicting information between the standard effective date section and the implementation plan schedule.**
- **Recommendation to match MOD-026 implementation plan.**
- **Misunderstanding of one unit vs. multiple unit plant application.**

The standard drafting team made the following changes in response to the comments received:

- **The Applicability Section 5.2.5 was added, as suggested.**
- **The effective date in the Implementation Plan has been corrected to match that shown in the Applicability section of the standard.**
- **Measure M1 was modified to address the previous test evidence requirements, and now reads:**

M1. Each Generator Owner and Transmission Owner will have evidence, such as example evidence provided in PRC-019 Section G, to show that its applicable Facility voltage regulating system controls and Protection System functions are coordinated with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. As applicable, this may include the following:

- **In service excitation system and voltage regulating system control, limiters and protection functions**
- **In-service generator or synchronous condenser protection system settings**
- **Generator or synchronous condenser capabilities, or**
- **Steady state stability limit.**

The coordination should include 1) verifying the in-service limiters are set to operate before the protection and the protection is set to operate before conditions cause damage to equipment assuming normal AVR

control loop and system steady state operating conditions, and 2) verifying the desired settings are applied to the in-service equipment.

The SDT did not adopt the recommendation to verify the initial 20 percent of applicable units within two years instead of one year of the effective date because it is desired to align the Implementation Plan of this standard to match the MOD-025-2 Implementation Plan. The SDT believes the elements of this standard should be performed as a precursor to performing Reactive power capability testing, specified by MOD-025-2.

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	It appears that Item 5.2.5 in the Applicability section is missing. We propose adding, "5.2.5 By the first day of the first Calendar quarter, five calendar years following Board of Trustee approval each Generator Owner and Transmission Owner shall have verified 100% of its applicable units".
Response: Thank you for your comment. The SDT has corrected this oversight.		
SPP Reliability Standards	No	The team would like to move out the initial 20% to 2 years and add a year to the following phases as well i.e 40% 3 years 60% 4 years etc. 5.2.5 seems to be missing from the standard

Organization	Yes or No	Question 5 Comment
Development Team		which doesn't include a bullet for 100% for those who need Board approval.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		
PPL Generation	Yes	
Dominion	No	The effective date implementation schedules contained in the standard and the associated Implementation Plan do not agree. Specifically, the standard indicates one year following regulatory and/or Board of Trustee approval where as the Implementation Plan indicates two year. Additionally, the standard at Step 5.2 does not include a sub-step for 100% of applicable units.
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
FirstEnergy	Yes	
SERC Dynamics Review Sub-committee		
NERC Staff	No	As written, the standard only addresses 80% compliance on generation and reactive sources that are not subject to regulatory approval. It appears that a section 5.2.5, similar to section 5.1.5, is missing from the Effective Dates section.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5.		
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		
Arizona Public Service Company	Yes	
Westar Energy	No	We would recommend the following implementation schedule:20% - 2 years after regulatory approval40% - 3 years after regulatory approval60% - 4 years after regulatory approval80% - 5 years after regulatory approval100% - 6 years after regulatory approval
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of application units in the Implementation Plan.		
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	Yes	In requirement R5.2 - there should be a sub-requirement R5.2.5 for 100% compliance at five calendar years?
Response: Thank you for your comment. The SDT has corrected the oversight concerning Section 5.2.5.		
Lakeland Electric		

Organization	Yes or No	Question 5 Comment
Salt River Project	Yes	
PacifiCorp	No	Measure M1 in proposed Standard PRC-019-1 requires current evidence to satisfy the coordination requirements of Requirement R1, Section 1.1, plus one previous dated set of evidence demonstrating the latest coordination review has been performed within the intervals prescribed in Requirement R1, Section 1.2. The latter category of evidence may not be available immediately upon the effective date of this proposed standard. The implementation plan should clarify how this Measure will be addressed during the phased-in implementation schedule.
Response: Thank you for your comment. The SDT agrees, and Measure M1 has been changed to address your concern.		
South Carolina Electric and Gas	No	There seems to be a mistake on the Implementation Plan versus the Standard. The implementation plan states two years for the first 20% of applicable units and the standard states one year. Please clarify this inconsistency.
Response: Thank you for your comment. The SDT has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.	No	Some of the requested data will reside in places not familiar to smaller entities and may require the use of consultants. The SDT may want to consider giving 2 years until the first 20% compliance level is reached because it will take time to set up a program.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2.		
New York Independent System Operator		

Organization	Yes or No	Question 5 Comment
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	For Cowlitz, this would be acceptable. However, Cowlitz only owns a few generation plants. We must defer to those who own many plants.
Response: Thank you for your comment.		
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	There is a conflict with the implementation periods stated within the body of Standard PRC-019-1 and the associated Implementation Plan. PRC-019-1 Section 5 Effective Date Step 5.1.1 states "(b)y the first day of the first calendar quarter, one year following applicable regulatory approval ... " [emphasis added]; however, the Implementation Plan states the Effective Date is "(t)he first day of the first calendar quarter two years following applicable regulatory approval ... " [emphasis added].Exelon requests that the implementation period be 2 years following regulatory approval. Nuclear generating stations have refueling outage schedule windows of approximately 18 months or 24 months (based on reactor type). An implementation period of 2 years will allow for any modifications to existing equipment be completed during a refueling outage.
Response: Thank you for your comment. The conflict between the Implementation Plan and the body of the standard has been corrected. The SDT does not believe the requirement to have 20 percent of applicable units compliant within the first year is an undue burden. For the example noted, the unit could be verified with the last 20 percent of Exelon's fleet, which gives over four years to comply with the standard.		
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission		

Organization	Yes or No	Question 5 Comment
Corporation		
Austin Energy	Yes	
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Electric Power	No	In light of the many other changes to standards currently proposed, and their implementations, AEP would suggest an additional year to the proposed implementation schedule to ensure a successful adaptation to PRC-019-1.The effective date for the 20% compliance milestone is inconsistent between the draft standard and the implementation plan, with one document allowing one year for compliance and the other allowing two years.
Response: Thank you for your comment. The SDT believes the five-year phase-in plan is appropriate. This corresponds to the phase-in period of MOD-025-2. The SDT has corrected the oversight concerning Section 5.2.5, and has corrected the Effective Date for the first 20 percent of applicable units in the Implementation Plan.		
Ingleside Cogeneration LP	Yes	The five year phased-in validation of settings is sufficient for Ingleside Cogeneration LP.
Response: Thank you for your comment.		
Wisconsin Public Service		

Organization	Yes or No	Question 5 Comment
Corp		
GE Energy		
ISO New England		
GenOn Energy	Yes	
Manitoba Hydro	No	-MH recommends that the effective dates for this standard be identical to MOD-026. This will allow entities to schedule all work and required outages simultaneously.
Response: Thank you for your comment. The SDT believes the elements of this standard should be performed as a precursor to performing Reactive power capability testing, as specified in MOD-025-2. The Implementation Plan is designed to match that of MOD-025-2.		
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator		
Gainesville Regional Utilities	Yes	
Ameren	Yes	Yes, only if settings need to be verified. No if testing needs to be done to verify settings.
Response: Thank you for your comment. The standard does not require testing. It only requires that the settings that are used for determining coordination have been verified to be the settings that are in service.		
Indeck Energy Services	No	For a plant with fewer than 5 units, implementation should be at the point that the unit finally satisfies the requirement, stated differently, a single unit station would comply at the 5 year point, not at the 1 year point. Why should multiple unit plants be given more time than single

Organization	Yes or No	Question 5 Comment
		unit plants. If having the units done in 5 years meets the BPS reliability need, then it should apply this alternative way. If BPS reliability needs compliance in 1 year, then all should comply.
Response: Thank you for your comment. The implementation plan is based on an entity's total number of applicable units, not the number of units installed at a plant. An entity that owns only one unit would have to be in compliance after one year, not five.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	Yes	
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

6. **Do you agree that the evidence, documents, and functions listed in Section G are sufficient for giving the Generator Owner/Transmission Owner examples of how the coordination can be demonstrated? If not, please provide suggested language changes to the Measure and supporting information in the Comment section.**

Summary Consideration: Specific changes were made to Section G of the standard based on comments received. These changes include:

1. **Providing example diagrams using nominal voltage and frequency as basis.**
2. **Correcting the SSSL radius calculation.**
3. **Information previously listed in the "under-excited limiters or minimum excitation limiters" and the "over-excited limiters or maximum excitation limiters" section has been combined into a bulleted list section.**
4. **The SDT changed "protective" to "protection" within the standard to be consistent with Section G.**
5. **The SDT added another reference document for use in calculation of SSSL.**

Several commentators were concerned that Section G prescribed a method for illustrating coordination of AVR limiter/protection functions with other Protection Systems. The SDT agrees there are several ways of demonstrating coordination, and does not prescribe a particular method. Any protective function that is enabled should be evaluated for proper coordination.

The SDT considered the request to remove distance relay and volts/hertz relay elements from the standard. The SDT believes these elements should remain in the standard because (a) the distance element should illustrate coordination with field forcing controls of the AVR, and (b) the volts per hertz function can operate with the unit on-line under certain operating conditions.

Organization	Yes or No	Question 6 Comment
LG&E and KU Energy		
Northeast Power	Yes	

Organization	Yes or No	Question 6 Comment
Coordinating Council		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates		
NERC System Protection and Control Subcommittee	No	The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.
Response: Thank you for your comment. The SDT has revised example diagrams using nominal voltage and frequency as basis.		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	While the team agrees with this evidence, some of the older units in the system may not have this information readily available.
Response: Thank you for your comment.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	We believe that the tutorial like language in Section G is not appropriate for a standard. There is an abundance of material available describing the coordination of generator protection equipment, such as textbooks, IEEE tutorials and even NERC tutorials. We believe referencing the documents could be appropriate and helpful. Even though the diagrams are listed as examples, we believe they might be interpreted a recipe to be followed.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comment. The SDT believes Section G provides applicable entities information on how compliance may be demonstrated without prescribing how to accomplish compliance. Entities may demonstrate compliance in ways other than those offered as examples in Section G.		
Santee Cooper		
PPL Generation	No	
Dominion	Yes	
FirstEnergy		At the moment we do not have comments on the proposed measures. We will review the proposed measures on the next draft and provide out input.
Response: The SDT will respond when comments are provided.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	The diagrams need to incorporate the permissible voltage and frequency ranges. For example, the P-Q diagram probably is based on 1 pu voltage and frequency.Further, Section G should address the system concerns described in Table 2 of the SPCS Technical Reference Document “Power Plant and Transmission System Protection Coordination,” for the generator protection functions that must be coordinated.
Response: Thank you for your comment. The SDT has revised the example diagrams using nominal voltage and frequency as basis. The SPCS Technical Reference Document addresses issues regarding generator and system protection coordination that are beyond the scope of PRC-019-1. At the same time, some of the coordination required in PRC-019-1 is not covered by the SPCS document. For example, the Loss of Field (40) function in Table 2 does not discuss coordination with the under-excitation limiter nor the steady-state stability limit.		
Public Service Enterprise Group	Yes	
SERC Generation sub-		

Organization	Yes or No	Question 6 Comment
committee		
ACES Power Members	Yes	
Arizona Public Service Company	No	30 minutes are more than adequate. All components reach steady state temperatures within that time. There is no need to be there more than 30 minutes.
Response: Thank you for your comment. We believe this comment refers to a different standard – probably MOD-025-2.		
Westar Energy	Yes	Examples for older units, where the information in the current examples are not readily available, could be included.
Response: Thank you for your comment. The examples provided in Section G are representative of both older units and newer units. Entities may demonstrate compliance in ways other than those offered as examples in Section G.		
Southern Company	Yes	
Tennessee Valley Authority GO	Yes	
Luminant Power	No	This item needs to coordinate with PRC-001 (System protection Coordination) and the future PRC-023-1 (generator loadability) standard currently under development. Section G indicates a distance relay (21) but does not indicate any timers that would be coordinated with the transmission provider. Propose removing this protective relay from Attachment 2.
Response: Thank you for your comment. The SDT believes the distance function (21) may need to be coordinated with excitation limiters and equipment capabilities, and should be evaluated if it is applied to a generating Facility. Coordination of that protective function with the transmission system is addressed by PRC-001 and PRC-023, as mentioned.		
Lakeland Electric		
Salt River Project	Yes	

Organization	Yes or No	Question 6 Comment
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	Yes	
Dynegy Inc.		
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	Cowlitz needs to confer with its consultant to form a more informed opinion. However, it appears to be reasonable.
Response: Thank you for your comment.		
Xcel Energy	Yes	
Lakeland Electric		
Exelon	No	In addition to the methodology listed, a provision should be allowed to use an alternative acceptable methodology that meets the intent of the Standard such as a methodology that uses impedance locus for loss of field for settings for the loss of field relays.Attachment G second formula is incorrect and should be corrected as follows:R = V2 g/2*(1/Xs+1/Xd) (Divide by 2)
Response: Thank you for your comment. The methodology listed in the example is not all-inclusive. The wording in Section G specifically states		

Organization	Yes or No	Question 6 Comment
"...the evidence of coordination associated with Requirement R1 may be in the form of ..." **The SDT has corrected the error in the formula for R.**		
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	Yes	
Wisconsin Electric	No	The following should be added to the list in Section G:1. under-excited limiters or minimum excitation limiters 2. over-excited limiters or maximum excitation limiters.
Response: Thank you for your comment. While all of the items identified were contained in the posted standard, the SDT has revised the standard by moving the example items to be considered for coordination from the list section referenced into a bulleted list section.		
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	Yes	
Constellation Power Generation	No	CPG believes that engineering documents detailing the coordination of the these components should be sufficient in lieu of coordination plots requiring software that is not commonly used by generators.
Response: Thank you for your comments. The SDT agrees there are several ways of demonstrating coordination, and does not prescribe a particular method.		
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 6 Comment
American Electric Power	No	There appear to be inconsistencies between the standard and appendix G. the standard uses the term "protective system settings" and "protection system settings" while the appendix uses the term "protection function".
Response: Thank you for your comment. The SDT has changed "protective" to "protection" within the standard.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP agrees with the concept of establishing a mode of operation that allows voltage regulators and limiters the first opportunity to deal with a voltage transient well before the corresponding Protection Systems are activated. However, we are concerned that protective relay settings must be always set in accordance with the Steady State Stability Limit (SSSL) as defined by NERC. There may be factors that are more limiting which require more sensitive settings - which should be acceptable if demonstrated on a P-Q, R-X or similar graph.
Response: Thank you for your comment. The standard does not prescribe that the protective relay settings must always be set in accordance with the SSSL. The SDT agrees that there may be limiting factors requiring more sensitive Protection System settings than required by the SSSL. Setting Protection Systems to the most limiting factor is acceptable.		
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	Yes	
Lincoln Electric System		
CPS Energy		

Organization	Yes or No	Question 6 Comment
Independent Electricity System Operator		
Gainesville Regional Utilities		
Ameren	No	(1)Volts per hertz and stator overvoltage protection are more applicable during unit start-up, not running conditions, where the system maintains the voltage and frequency. These should be eliminated. (2) The standard needs to be clear on what relay elements need to be included if enabled. (3) The standard needs to be clear on how to plot the diagrams to incorporate operating voltage. For example the generation is most stable while maintaining maximum permissible voltage and producing the most VAr's possible. Therefore should the plot be at maximum voltage of 1.05pu. (4) It would be helpful to have some reference for where the development of the Steady State Stability Limit equations in the draft standard could be found. None could be found on the NERC website. We are concerned that the method proposed for calculating steady state stability limits does not include sufficient conservatism.
Response: Thank you for your comment. (1) The SDT believes that it is possible to encounter volts per hertz conditions during normal operation, so this needs to be evaluated. (2) The SDT believes any protection functions that are enabled should be evaluated for proper coordination. (3) The SDT does not prescribe what voltage or frequency to use when evaluating coordination. The entity performing the evaluation can choose the voltage and frequency value to use. (4) The SDT has added a technical reference regarding SSSL equation development to the standard.		
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

7. Do you agree with the data retention language listed in the Compliance section of the draft standard? If not, please comment and provide alternative data retention language.

Summary Consideration: Forty-six stakeholders agreed, 27 stakeholders disagreed, and 18 stakeholders had no opinion.

Three stakeholders were concerned that the TO might be required to retain compliance data for generation equipment that it does not own. The applicability requirements in the draft standard have been clarified.

Eleven stakeholders were concerned that the data retention requirements were unclear, especially as the standard is being phased in. Stakeholders were also concerned that data retention requirements might be excessive. The SDT revised the Measure M1 and the data retention requirements for clarity and to be consistent with the NERC Compliance Process Bulletin #2011-001.

Organization	Yes or No	Question 7 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section		

Organization	Yes or No	Question 7 Comment
needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers.		
Imperial Irrigation District (IID)	Yes	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	
NERC System Protection and Control Subcommittee	Yes	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	
SPP Reliability Standards Development Team	Yes	For new units or units that haven't changed you would not have prior data to provide. The drafting team may need to think about rewording to address this issue.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	Yes	
Santee Cooper		

Organization	Yes or No	Question 7 Comment
PPL Generation	Yes	
Dominion	Yes	
FirstEnergy	No	Section 1.2 of the Compliance section is missing a time frame for data retention. Timeframes consistent with CEA routine audit cycles should be added to this section.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members	No	The data retention for M1 may not be consistent with NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC appears to require some level of evidence for the entire audit period.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 7 Comment
Southern Company	No	Only the last two documentation sets are needed to prove the intervals are being met. ALL previous sets are not necessary. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Tennessee Valley Authority GO	Yes	
Luminant Power	No	Once coordination is completed, the retention shall be until the unit is retired or a system change has occurred, plus any coordination document that was in effect during the current audit cycle.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Lakeland Electric	No	The word “prior” lacks specificity. Proposed: “...shall retain the latest evidence of compliance with Requirement R1, Measure M1 dating back to most recent audit period.”
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Salt River Project	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric	Yes	

Organization	Yes or No	Question 7 Comment
Cooperative, Inc.		
Dynegy Inc.	Yes	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	Yes	
Cowlitz County PUD	Yes	
Xcel Energy	Yes	
Lakeland Electric		
Exelon	Yes	
American Wind Energy Association	Yes	
Tacoma Power	Yes	None
Georgia Transmission Corporation		
Austin Energy	No	Initial compliance, within the first audit period, should be based on one evidentiary document set. Subsequent compliance, after the first audit period, may include the most current and the previous evidentiary document set.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		

Organization	Yes or No	Question 7 Comment
Wisconsin Electric	Yes	
Great River Energy		
BC Hydro	Yes	
Northeast Utilities	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers		
Constellation Power Generation	Yes	
Consolidated Edison Co. of NY, Inc.	No	The data retention section of the standard is vague with respect to responsibilities of the various parties. It would appear that the data retention responsibility falls to either the Generator Owner or the Transmission Owner with a synchronous condenser on its system. If, however, the Transmission Owner is also required to retain compliance data of generator and transmission system coordination, a substantial amount of time may be required to gather this information as it does not exist today. At the very least, once this standard becomes effective an effort with generators will be needed to assemble the appropriate information demonstrating the proper coordination of transmission system and generator relaying. This could take a

Organization	Yes or No	Question 7 Comment
		considerable amount of time to complete. Responsibility for data retention should be placed on the owner of the equipment.
Response: Thank you for your comment. The equipment owner has responsibility for data retention. If a Transmission Owner owns a synchronous condenser, then the Transmission Owner is only required to retain compliance data for that equipment. The SDT agrees the Application section needed to be clarified, and has modified Section 4.1.2 to state that the standard only applies to Transmission Owners that own synchronous condensers		
American Electric Power	Yes	
Ingleside Cogeneration LP	Yes	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	Yes	
Duke Energy	No	Electronic documentation of coordination efforts should be considered accecptible as long as a revision history is maintained. Past history is not significant to present/future reliability. Only the presentation documentation of coordinations is needed along with proof that the results have been implemented. The bullet listed under 1.2 Data Retention implies that all records need to be kept indefinitely.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Lincoln Electric System		

Organization	Yes or No	Question 7 Comment
CPS Energy		
Independent Electricity System Operator	No	We interpret the wording "shall retain the latest and the prior evidence of compliance with Requirement R1, Measure M1" to mean the evidence for the last and the one before last compliance assessments. We question the need to keep the two sets of evidence. Keeping only the evidence for the last compliance assessment would suffice.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Gainesville Regional Utilities	Yes	
Ameren	No	Retaining studies for 10 years seems unreasonable and could lead to confusion. Retaining data from previous audit seems reasonable to assure studies are being done every 5 years. Regarding R1.1.2, in order to limit the need to take unnecessary outages, which may be required to verifying settings, verification of settings should be limited to a one time only, upon installation or setting change.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Indeck Energy Services	No	One year history should be sufficient. It's about the verification, not keeping paper or electronic records forever.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency	No	IMPA is answering this question in conjunction with question 9. IMPA believes that the study should happen initially and only if a change is made or equipment is modified. If using this approach, the previous evidence and the new evidence should be retained.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	Yes	

8. Are you aware of the need for any regional variances to this standard? If yes, please explain in the comment section.

Summary Consideration: By a large majority, stakeholders do not believe a regional variance is needed. There are very few instances known that might justify having a regional variance. The four stakeholders answering "yes" to this question did not provide specific reasons why a variance might be needed.

Organization	Yes or No	Question 8 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	No	
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	No	
NERC System Protection and Control Subcommittee	No	
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	No	

Organization	Yes or No	Question 8 Comment
SPP Reliability Standards Development Team	No	
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	No	See comment 2 for item 9 below.
Dominion	No	
FirstEnergy	No	We are not aware of the need for a variance at this time.
Response: Thank you for your comment.		
SERC Dynamics Review Sub-committee		
NERC Staff	No	
Public Service Enterprise Group	Yes	
SERC Generation sub-committee		
ACES Power Members		

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	No	
Tennessee Valley Authority GO	No	
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	No	
APS		being intentionally left blank (no answer to be provided)
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and	No	

Organization	Yes or No	Question 8 Comment
Transmission, In.		
Cowlitz County PUD	No	
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power	No	None
Georgia Transmission Corporation		
Austin Energy	No	
Wisconsin Electric	No	
Great River Energy		
BC Hydro	No	
Northeast Utilities	No	
Constellation Power Generation	No	
Consolidated Edison Co. of	No	

Organization	Yes or No	Question 8 Comment
NY, Inc.		
American Electric Power	No	AEP is not currently aware of any need for regional variances to this standard.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp		
GE Energy		
ISO New England		
GenOn Energy		
Manitoba Hydro	No	
Duke Energy	Yes	There may be regional variations in regional critical size criteria.
Response: Thank you for your comment. The SDT cannot respond if a specific regional variation concern is not identified.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	No	
Gainesville Regional Utilities	No	
Ameren	No	

Organization	Yes or No	Question 8 Comment
Indeck Energy Services		
Oncor Electric Delivery Company LLC	Yes	
Indiana Municipal Power Agency		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

9. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain in the Comment section.

Summary Consideration: The drafting team received many suggestions for improvements to the standard. Several stakeholders commented on the Applicability section, requesting clarity with regard to Transmission Owners' obligations, threshold equipment nameplate ratings, or capacity factor exemptions. The GVSDT revised the Applicability section to clarify that only Transmission Owners owning synchronous condensers are specified as applicable entities in the standard. The applicability section specifies the same equipment nameplate rating thresholds defined in the Compliance Registry criteria. The standard does not allow other exemptions.

Several stakeholders commented on various aspects of Section G. The GVSDT considered these comments and made minor changes for clarity.

A few stakeholders requested changes to Measure M1 and the Data Retention section to clarify what evidence is necessary during the implementation period and also following changes requiring a coordination review. The GVSDT revised the language to clarify intent and also satisfy the NERC Compliance Guideline #2011-001.

A few stakeholders stated Requirement R1 could be interpreted to require protection settings that operate within the equipment capability. The GVSDT revised the R1 language to clearly state that protection must be set to prevent equipment damage.

A couple of stakeholders indicated the standard lacked clarity on which protective functions must be coordinated with limiters and equipment capability. In response, the GVSDT stated all in-service protective functions that might operate during steady-state system conditions must be evaluated and opted not to revise the standard.

Two stakeholders indicated the standard should require coordination be evaluated with the strongest transmission line out of service. The GVSDT believes doing this would add a great deal of complexity to the process without a corresponding gain in reliability.

Two stakeholders indicated the emphasis on coordination would prevent proper protection of the equipment. The GVSDT disagrees.

Two stakeholders took issue with the terms "in service," and "Point of Interconnection." The GVSDT maintained the term "in-service" (as defined in Footnote 1) in the standard and removed the term "Point of Interconnection" from the standard.

One stakeholder identified inconsistencies between the Title, Purpose, and Requirement R1 language. These inconsistencies were resolved.

One stakeholder identified the discrepancy between the Comment Form and the standard regarding synchronous condenser applicability nameplate rating threshold, and also noted that part of the Effective Date section was missing. In response, the GVSDT provided explanation for the discrepancy identified, and corrected the Effective Date section.

A few individual comments were received requesting the standard be revised to 1) include static var compensators, 2) specify a complete list of elements to be coordinated in R1, 3) change the coordination review time frame following a change in settings or equipment, and 4) add a requirement to activate and set excitation limiters. The GVSDT does not agree the standard would be improved by incorporating these suggestions.

Organization	Yes or No	Question 9 Comment
LG&E and KU Energy		
Northeast Power Coordinating Council	Yes	Related to the "Examples of Coordination", the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		
Imperial Irrigation District (IID)	No	
IRC Standards Review Committee (joint comments)		
Pepco Holdings Inc Affiliates	Yes	Based on the Requirements and Measures identified in the standard it is unclear why the standard was made applicable to Transmission Owners; unless the standard is intended to only

Organization	Yes or No	Question 9 Comment
		apply to Transmission Owners that own synchronous condensers. If that is the case, Section A-4.1.2 should be re-written as follows: “Transmission Owner that owns a synchronous condenser.” This qualification is consistent with other PRC standards (PRC-010, PRC-015, PRC-023, etc.) where applicability to a specific sub-set of Transmission Owners is clearly defined.Do the requirements in this new standard overlap or duplicative with PRC-001 R3 and R5?
Response: Thank you for your comment. The SDT agrees proposed language for Section 4.1.2 will improve standard clarity, and has modified the standard accordingly.		
NERC System Protection and Control Subcommittee	Yes	Requirement R1: The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G. Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions.Requirement R1, part 1.1.2: The word "check" is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as "Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment."Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project the Generator Owner should be required to verify coordination prior to placing the revised equipment or settings in-service.The SSSL derivation should consider the impact of system strength (e.g., strongest transmission line source out-of-service), generation saturation, and AVR status to assure an appropriately conservative limit.Implementing a UEL based on the steady-state stability limit may prevent under-excited operation, which would otherwise be stable and useful in managing system conditions (such as during system restoration activities or in lightly-loaded areas that need to sink reactive power to control voltage or synchronizing a generator to a long line).Where the Generator Owner and Transmission Owner are separate entities, there is difficulty for the Generator Owner to obtain system impedance information and

Organization	Yes or No	Question 9 Comment
		keep it up to date as the transmission system may be re-configured during on-going operations; this information is necessary to represent the SSSL.The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.
Response: Thank you for your comment. The SDT believes all in-service protection functions for a generating unit or synchronous condenser should be evaluated for coordination with the limiters, capabilities and protection under steady state conditions at nominal voltage and frequency. **This standard does not require evaluating coordination under transient conditions.** **The SDT believes that all protection functions, including generator backup distance and backup overcurrent, can be coordinated with the limiters and capabilities, as shown on Attachment 2, when considered under steady-state conditions using nominal voltage and frequency.** **The recommendation to demonstrate that the settings used in the coordination evaluation are the same settings applied to the in-service equipment is addressed by Measure M1.** **The SDT agrees that removing lines from service will affect the SSSL characteristic, however this is normally a fairly small change since the equivalent transmission system; impedance is much smaller than the step-up transformer impedance. Proper coordination would allow enough margin between the SSSL with all lines in service and the protection characteristics to allow for minor variations in the SSSL.** **The SDT does not believe a Transmission Owner would refuse to provide a Generator Owner with information requested for a reliability reason.** **The SDT agrees that the primary reason for Protection Systems is to protect power system equipment. The coordination philosophy described is essentially a restatement of that found in Section 3.5 of the NERC Power Plant and Transmission System Protection Coordination document.**		
Midwest Reliability Organization's NERC Standards Review Forum (NSRF)	Yes	Consider adding a note to Attachment 1, which states that the type of D curve should be specified (i.e. based on the data reported per the MOD-010 standard, the data reported per the MOD-025-2 standard, or some other basis).
Response: Thank you for your comment. The SDT does not believe it should prescribe specific evaluation evidence. It is anticipated the equipment owner will utilize information obtained per MOD-010 for the coordination evaluation specified.		
SPP Reliability Standards	Yes	It seems there is room for clean up in the posted standard.

Organization	Yes or No	Question 9 Comment
Development Team		
SERC Planning Standards Subcommittee		
Idaho Power-Power Production	No	
Santee Cooper		
PPL Generation	Yes	PPL Generation suggests the following changes:1. Consider making this standard applicable to generation facilities having a capacity factor for the past three years averaging over 10%. The basis for this request: As presently written this Applicability would require compliance for a small, emergency genset if located in a baseload facility interconnected > 100 kV. 2. In Requirements R.1, R1.1.1, R1.2 and elsewhere where the term "capability" is used, consider using the term "trip limit". As currently written, it appears that Requirement 1.1.1 is semantically misdirected in requiring protectives to be set below equipment capabilities. A capability is what the unit can actually do (ref. MOD-024 and 025). It is not the limit beyond which damage, instability or other problems may occur. A unit with a 875 MVA GSU and 900 MVA generator, for example, may have a real power capability of only 750 MW based on boiler and turbine limitations. It is not possible to have trips set below a unit's capability, unless PRC and MOD apply different meanings for this term, which would not be suitable.Confusion may be caused by generator D-curves also being called “capability curves,” but here also one would not want to require that generator never be operated at the D-curve value.
Response: Thank you for your comment. The Applicability section of this standard correlates with the applicability section of MOD-025-2 because it is anticipated the coordination evaluation performed for PRC-019-1 will be accomplished before the Reactive capability testing required by MOD-025-2. Requirement 1, part 1.1.1, has been revised to address concern with the coordination of protection and capability. D-curves are one way to define equipment capability (and are often called “ Reactive capability curves”).		
Dominion	Yes	1) the phrase “Generating equipment”, in the 3rd bullet of R1, be changed to “Generator” to be consistent with the usage under bullets 1 & 2. 2) The title and purpose of the document do not address synchronous condensers as addressed in Requirement R1; 3) if the standard includes synchronous condensers, why are static VAR compensators not included? The

Organization	Yes or No	Question 9 Comment
		following bullets under R1 are too generic. Should specifically outline required parameters.ï‚•ï€ In-service 1excitation system and voltage regulating system control, limiters and protection functions o In-service generator or synchronous condenser protection system settings o Generating equipment or synchronous condenser capabilities o Steady state stability limit We recommend replacing the bullets with the following: o Generator or syn. Condenser capability curves. o Steady state stability limit. o Loss of field zone 1. o Loss of field zone 2. o Loss of field trip. o Under excitation limiter. o Over excitation limiter. o Power factor line. o Backup over current settings. o Instantaneous field current trip. o Instantaneous field current limit. o Volts per hertz.
Response: Thank you for your comment. (1)The SDT has revised R1 based on your suggestion. (2) The SDT has revised the Title and Purpose based on your suggestion. (3) The SDT has determined that variable static Reactive resources not located at generating Facilities are not within the scope of this standard. As Pepco states in their comment to Question 3: "SVC protective devices are set assuming the full bank is in service. Synchronous machines, however, are a different story entirely. The quantity of Reactive power produced by, or drawn into, the machine is a function of the machine field current. In an under-excited condition, the unit may loose synchronism or trip via loss of field protection, unless the voltage regulator (min. excitation limiter) is properly set and coordinated with the machine's capability and protective devices. Similarly, excessive Var output and/or terminal overvoltage caused by over-excitation of the field can result in equipment damage or unit tripping, unless the voltage regulator is properly set and coordinated with the machine's capability and protective devices." In addition, IESO points out in their response to Question 3: "The SVCs serve quite different purpose and react to system conditions quite differently compared to their generator/synchronous condenser counterparts." (4) The bulleted list in R1 are categories that need to be considered when performing coordination evaluation, and is not intended to be a complete list of specific functions.		
FirstEnergy	Yes	M1 requires that the GO will have evidence that "...voltage regulating system controls and protection functions are coordinated with the generating unit and generating Facility capabilities and protective system settings applied to in-service equipment as specified in Requirement R1, Section 1.1, and one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2." For the first verification cycle this would require that units would have to prove compliance as much as 4 years before the standard became enforceable. This is akin to setting up a traffic camera in a 35 mph zone in March, changing the speed limit in that zone to 25 mph in July, and going back and writing tickets for every car that exceeded 25 mph from March through June. This needs to be clarified. Requirement R2 (shown as 1.2 in the standard) should have a violation risk factor of MEDIUM instead of HIGH. Furthermore, it seems that the phrase "within 90 days of making a change to the generating equipment, voltage control limiter settings, or protective function settings that would affect the coordination" is not necessary because a change to equipment

Organization	Yes or No	Question 9 Comment
		setting would already require coordination per Requirement R1. We suggest removing this part of 1.2 (or R2).
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001. With respect to your suggestion to remove Requirement 1, part 1.2, the SDT disagrees and believes verification of coordination needs to be performed in a timely manner following a change to equipment or settings.		
SERC Dynamics Review Sub-committee		
NERC Staff	Yes	The standard lacks clarity on which types of protection functions must be coordinated. The standard should specify which types of protection functions must be coordinated if they are present on the generating unit, such as the list in Section G.This should be consistent with protection coordination described in the SPCS Technical Reference “Power Plant and Transmission System Protection Coordination.” Additionally, Attachment 2 could be interpreted to require coordination for protection systems that cannot be coordinated (e.g., the generator backup distance and backup overcurrent functions are required to detect faults that may result in an apparent impedance inside the SSSL) or do not require coordination (e.g., the generator out-of-step function will operate only for an unstable power swing and will not operate for stable operation within its operating characteristic). These protection functions should be removed from the figure or clarification should be added that the standard does not require coordination of these protection functions.Requirement R1, part 1.1.1: The standard emphasizes preventing tripping of generating units and generating facilities due to miscoordination. Another aspect of coordination is to coordinate the protections and controls to coordinate with the equipment capability. Without guidance or direction, the standard could have the unintended consequence of overly conservative settings that limit the ability of the facilities to respond to system disturbances, or inadvertently create a common-mode failure trip point across a generation fleet.Requirement R1, part 1.1.2: The word “check” is subject to interpretation and step 1.1.1 in some cases will verify existing settings rather than determine settings. Part 1.1.2 should be revised to address these issues, such as “Demonstrate that the settings used to verify coordination in part 1.1.1 are applied to the in-service equipment.”Requirement R1, part 1.2: When the generating unit equipment or settings are modified as part of a planned project, the Generator Owner or Transmission Owner should be

Organization	Yes or No	Question 9 Comment
		required to verify coordination PRIOR to placing the revised equipment or settings back in-service. It is important to note that protection setting changes on the transmission system may necessitate generating unit protection setting changes which in turn require a review of coordination with the generating unit or plant voltage regulating controls. While coordination between the transmission system and generating unit protection settings is outside the scope of this standard it is important that this coordination is required by in a reliability standard.The examples emphasize steady-state limits and capability curves without mention of the short-term generating unit capabilities. Proper coordination should also apply to transient response of the generating unit and its associated limiters to meet the reliability objective of this standard. Focusing examples on steady-state coordination may be misleading and result in miscoordination for transient events. Of particular concern is the transient response of exciters in field-forcing during system disturbances; loss of reactive support from generation during such events can be catastrophic and lead to cascading.The foremost reason for protective relaying is to protect power system equipment. There is a concern that the real purpose of relaying may be lost in the overwhelming emphasis of its coordination with controlling equipment throughout the document. The generator protective relays are there to protect the generator and its associated equipment and the standard should acknowledge that this primary objective cannot be violated to obtain the desired coordination.

Response: Thank you for your comment. The SDT believes all in-service protection functions for a generating unit or synchronous condenser should be evaluated for coordination with the limiters, capabilities, and protection under steady-state conditions at nominal voltage and frequency.

This standard does not require evaluating coordination under transient conditions.

The SDT believes that all protection functions, including generator backup distance and backup overcurrent, can be coordinated with the limiters and capabilities, as shown on Attachment 2 ,when considered under steady-state conditions using nominal voltage and frequency.

The recommendation to demonstrate that the settings used in the coordination evaluation are the same settings applied to the in-service equipment is addressed by Measure M1.

With regard to the suggestion to include transient response in the coordination evaluation, the SDT believes the function of the limiters is to prevent operation in regions that would damage the equipment during transient conditions, and that proper coordination of limiters with protection will prevent improper tripping of the equipment.

The SDT agrees that removing lines from service will affect the SSSL characteristic, however this is normally a fairly small change since the equivalent transmission system impedance is much smaller than the step-up transformer impedance. Proper coordination would allow enough margin between the SSSL with all lines in service and the protection characteristics to allow for minor variations in the SSSL.

Organization	Yes or No	Question 9 Comment
The SDT does not believe a Transmission Owner would refuse to provide a Generator Owner with information requested for a reliability reason. **The SDT agrees that the primary reason for Protection Systems is to protect power system equipment. The coordination philosophy described is essentially a restatement of that found in Section 3.5 of the NERC Power Plant and Transmission System Protection Coordination document.**		
Public Service Enterprise Group	Yes	The SDT should review R1. As it reads now, the phrasing of the first paragraph makes it difficult to understand what equipment is included for generator units and what is included for synchronous condensers.
Response: Thank you for your comment. The SDT has revised R1.		
SERC Generation sub-committee		
ACES Power Members	Yes	In part 4.2.3 of the Applicability section, the phrase "regardless of size included in a Transmission Operator's restoration plan" should be struck. It is redundant with definition of Blackstart Resource.
Response: Thank you for your comment. The SDT believes it is necessary to duplicate Registry criteria language in the applicability section to clarify that the standard is applicable to other equipment in addition to synchronous condensers.		
Arizona Public Service Company	Yes	
Westar Energy	No	
Southern Company	Yes	1) The last sentence of Measure M1 is not needed. There is no need to require evidence of the change implemetation, only coordination verification is needed. The requirement for documentation of change identification or implementation is not part of Requirement R1. 2) In several places in the posting documents there is a descrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 3) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 4) Section 5.2.5 is missing from effective date in the draft standard.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. (1) The measure supports evidence needed to demonstrate compliance with the 90-day requirement specified in R1.2. Regarding comments (2), (3), (4) Noted, discrepancies have been corrected.		
Tennessee Valley Authority GO	Yes	We recommend that the minimum unit rating to be applicable to this standard should be 75 MVA, and the aggregate plant size to be applicable should be 100 MVA.
Response: Thank you for your comment. The Applicability section of the standard is based on the Registry criteria, and the SDT does not have sufficient technical justification to deviate from this criteria.		
Luminant Power	No	
Lakeland Electric		
Salt River Project	No	
PacifiCorp	No	
South Carolina Electric and Gas	Yes	In regards to Measure 1 it should be clarified that only the latest coordination review will be needed for the first 5 years after the standard is implemented and only after 10 years will the entity be required to show both latest and prior evidence of compliance for 100 % of the applicable units. As stated, it looks like the standard would require the entity to verify the existence of coordination twice on 20% of the applicable units in the first year to show evidence of a latest and prior coordination for those units. If an entity were to be audited 3 years after the effective date of the standard, they would have to show coordination of 60% of the applicable units and should not be required to show a prior documented coordination since a 5 year interval would place the prior coordination possibly before the effective date of the standard. This would also apply in the situation of a newly built applicable unit in which there would be no prior evidence available; only the latest.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
APS		being intentionally left blank (no answer to be provided)

Organization	Yes or No	Question 9 Comment
Associated Electric Cooperative, Inc.	No	
Dynegy Inc.	No	
New York Independent System Operator		
Tri-State Generation and Transmission, In.	No	
Cowlitz County PUD	Yes	Cowlitz understands the difficulty the SDT is under. Although the base line of applicability is in question, this Standard is justifiable and will not present too great a burden to comply with.
Response: Thank you for your comment.		
Xcel Energy	No	
Lakeland Electric		
Exelon	No	
American Wind Energy Association	No	
Tacoma Power		None
Georgia Transmission Corporation		
Austin Energy	No	

Organization	Yes or No	Question 9 Comment
Wisconsin Electric	Yes	1. R1.2 needs to be clarified, and more time allowed. The phrase, "within 90 days following the identification or implementation of systems, equipment, or setting changes..." is vague, and should be replaced with "within 120 days of modifications made to systems, equipment, or setting changes...". The requirement should clarify that the clock starts 120 days after the date that the affected generator returned to service following the modifications. 2. It is not clear how wind generators can be subject to this standard. The information in Section G does not relate to wind machines.
Response: Thank you for your comment. (1) The SDT believes that 90 days is sufficient time to perform a coordination evaluation, and is an appropriate time frame that supports reliability. The SDT believes current language with respect to "starting the clock," is appropriate for covering the possible scenarios. (2) The standard is technology neutral. The information in Section G does not necessarily apply to a particular type of technology. The equipment owner is responsible for providing appropriate compliance evidence.		
Great River Energy		
BC Hydro	Yes	The note in section G may have to be revisited. The main issue is that active excitation limiters can prevent a unit from unneccessary tripping during system transients. The standard should encourage activation and proper setting of avaiable excitation limiters
Response: Thank you for your comment. The SDT believes it is beyond the scope of this standard to recommend additional practices.		
Northeast Utilities	Yes	Related to the "Examples of Coordination", the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		

Organization	Yes or No	Question 9 Comment
Constellation Power Generation	No	
Consolidated Edison Co. of NY, Inc.	Yes	Related to the “Examples of Coordination”, the P-Q diagram, the R-X diagram, and the Inverse Time Diagram are not all interchangeable. For this Standard only the P-Q Diagram can be used for compliance because it provides both under and over excitation capabilities of the machine. This curve is commonly used in industry and is readily understood by Engineers, System Operators and Generator Operators. The R-X Diagram example should be considered optional if impedance relays are used that reach beyond the generator-transformer protection zones. However, the R-X Diagram should not be mandatory. Concerning the Inverse Time Diagram, this example should be deleted since it only provides information on machine overexcitation capabilities and does not address underexcitation settings.
Response: Thank you for your comment. The diagrams in Section G are optional and provided as examples for industry. It is expected more than one diagram would be needed to demonstrate coordination for most units. The GVSDT has revised Section G to clarify this point.		
American Electric Power	Yes	Measure 1 states the need for “one previous dated set of evidence that demonstrates the latest coordination review has been done within the intervals specified in Requirement R1, Section 1.2.”, yet this would not be required by the standard until five years following the initial coordination.
Response: Thank you for your comment. The SDT has revised the Measure M1 and the Data Retention sections to address your concerns. Data Retention has been written to be consistent with the NERC Compliance Process Bulletin #2011-001.		
Ingleside Cogeneration LP	No	
Wisconsin Public Service Corp		
GE Energy		The fourth bullet in Part G “Reference,” paragraph beginning with “Equipment limits,”, page 6: The word “stator” should be removed, in order to make the over voltage protection limits applicable to non-synchronous machines.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comment. The SDT has revised language accordingly.		
ISO New England		
GenOn Energy	Yes	In some ways, the requirements are too subjective in determining what protection and limiters are subject to coordination. In other ways, the standard provides insufficient or contradictory requirements in defining how coordination is achieved, even for well established protection practices. It is difficult to define all-inclusive coordination principles with so many variables in a simple straightforward standard. As written, the standard is a compliance risk to the applicable entities based upon future arbitrary and subjective interpretation by compliance organizations. Vivid examples are provided in Attachment 1. Loss-of-Excitation Zones 1 & 2 does not “coordinate” with the Steady State Stability Limit. In the diagram of the generator capability curve, SSSL is reached prior to the Loss-of-Excitation protection, contrary to R1.1.1, requiring the protection to operate ahead of the SSSL. Also, Loss-of-Excitation Zones 1 & 2 exceeds the generator capability curve, and does not fulfill R1.1.1 that requires protection to operate before conditions exceed equipment capabilities. Other variables with indirectly relationships are subject to future interpretation. A generator stator may have overvoltage protection set at 118% with a 2 second time delay, allowing it to meet PRC-024-1 ride through capability. Overvoltage protection also has a correlation to field current limiters. To insure and demonstrate absolute “coordination” with a field current limiter under all circumstances, it may be necessary to reduce the field current limit. The move will be counter productive to system performance in most transient conditions, but may be required to insure “coordination.”The SDT should make specific requirements of defined scope rather than broad, subjective, and open-ended requirements, i.e. 1) Volts/Hz limiters shall coordinate with Volts/Hz protection, 2) Under excitation limiters shall coordinate with steady state stability limits and loss-of-field protection, and 3) field current limiters shall coordinate with field current capability. The standard should exclude statements that the protection must operate before conditions exceed equipment capability. It will be difficult to provide definitive evidence of compliance for the use of many protection elements on older equipment with no documentation of equipment capability to withstand conditions such as Volts/Hz. If a generating unit is rated for +/- 5% terminal voltage, how is the generator’s overvoltage withstand capability demonstrated to PRC-024-1 criteria. In a compliance world of absolutes, Generator Owners may not be allowed to use general “rules of thumb” when coordinating protection. In ways that are counterproductive to reliability and equipment protection, Generator Owners could end up removing protection

Organization	Yes or No	Question 9 Comment
		elements when it cannot be demonstrated that it operates before the condition exceeds equipment capabilities.Calculation of the steady state stability limit requires the transmission system Thevenin equivalent impedance. Therefore, it is necessary for the standard to require Transmissions Owners to provide Generator Owners this impedance within 30 days of request. Likewise, the allocated time for Generator Owners to perform coordination studies should increase by 30 days or more to 120 days.In R1.2, a five year coordination study interval is an unnecessarily short duration for generating units without significant changes in the generator protection or an AVR replacement. A company with 150 generating units will average 2.5 coordination studies per month on a non-stop continuous rotation. Ten years is a more appropriate cycle for a coordination study on a unit with no changes. The wording used to trigger an examination should be specific and defined, rather than the ambiguous and nondescript statement of “changes that are expected to affect this coordination.” To meet compliance, it will be necessary to expend needless effort for the possible interpretations of “changes” that otherwise will have little or no impact for the intent or purpose of this standard. Suggest rewording R1.2, “Each Generator Owner or Transmission Owner shall verify the coordination indentified in Requirement R1 at least once every ten years or within 120 calendar days following modifications impacting coordination when the following activities occur: 1) a change in AVR limiters or AVR protection for over-excitation, underexcitation, Volts/Hertz, stator voltage, or field current, or 2) generator protection changes for stator voltage, loss-of-excitation, or Volts/Hertz protection.”For only 30 days of differences (90 to 120), VSLs expand from Lower to Severe. Considering the justifiable allowance for 20% of the fleet to go 5 years without demonstrated coordination, the logic for the acceleration of severity over such a short time duration is not understood.
Response: Thank you for your comment. In response to comments regarding coordination between the loss of field protection and the SSSL in Attachment 1, the loss of field trip curve does coordinate with the SSSL. The Zone 2 and Zone 1 loss of excitation functions are providing backup protection to the primary loss of field trip. With regard to your suggestion of defining specific methods for evaluating coordination, the SDT intends the standard to be technology neutral and cannot define coordination methodologies for all current and future generating technologies. The SDT has revised the wording in R1 to clarify that protection should protect the equipment and may allow capabilities to be exceeded when appropriate. The verification time interval has been set to coordinate with MOD-025-2. Once an initial coordination evaluation has been completed, subsequent verification should not be a hardship. In response to your comment, the SDT has revised language used to trigger an evaluation. The VSL levels are set in accordance with NERC guidelines, and are appropriate for reliability concerns associated with equipment changes.		
Manitoba Hydro	Yes	-The standard should take into account generating units whose capacity is determined based

Organization	Yes or No	Question 9 Comment
		upon the run of the river where it may be difficult to test at design capacity. We suggest that an engineering methodology/calculation be acceptable for these units
Response: Thank you for your comment. The SDT believes the capability of the equipment does not change, even though equipment output may be restricted due to factors, such as run of the river. This standard does not require testing.		
Duke Energy	Yes	1) In several places in the posting documents there is a discrepancy in the size of the synchronous condensor that is in the scope of the standard, some places list the size criteria at 20 MVA, and others state 50MVA. 2) The Implementation plan document effective date is incorrect for the 20% completion step - it states two years rather than the appropriate one year. 3) Section 5.2.5 is missing from effective date in the draft standard. 4) R1.1.1.1 seems to infer that the 40 relays should be set inside the Capability curves and the SSSL. The 40 relay should be set inside the SSSL but may be outside the capability curves as it is intended to prevent a pole slip. AVR protective functions may be set to protect the capability curves.
Response: Thank you for your comment. Regarding comments (1), (2), noted discrepancies have been corrected. (4) The SDT has revised the wording in R1 to clarify that protection should protect the equipment and may allow capabilities to be exceeded when appropriate.		
Lincoln Electric System		
CPS Energy		
Independent Electricity System Operator	Yes	1. The standard introduces a local definition: “in-service”, that is subject to interpretation. Does “in-service” mean:- Installed but may or may not be put to service (e.g. mothballed)?- Installed and can be put to service at any time?- Installed and on-line?Generators/synchronous condensers will have a reliability impact only when they are connected to the grid (put on-line). However, the timing of these facilities to be put on-line is at the discretion of the GOs and perhaps under some conditions specified by other entities such as the TOP or RC. It is thus conceivable that installed facilities can be put on-line at any time. To ensure proper reliability performance, we suggest to change “in-service” to “installed” to make sure the facilities meet the standard requirements if and when they are put on-line. 2. R1.2: The wording: “verify the existence of the coordination” does not drive home the intent of ensuring the settings are coordinated and reviewed once every 5 years or as changes occur. We suggest to change R1.2 to read: “shall review and revise as necessary the coordinated settings identified in

Organization	Yes or No	Question 9 Comment
		Requirement R1 at least once every five years or within….”
Response: Thank you for your comment. Footnote 1 defines “in service” as functions that are installed and activated. Many relays have multiple protection functions that would be “installed,” but not necessarily activated. Installed protection functions that are not active do not need to be evaluated for determining proper coordination. The SDT believes standard language for verifying the existence of coordination is adequate.		
Gainesville Regional Utilities	No	
Ameren	Yes	(1) Standard needs to be more specific and clear on what evidence is need for 1.1.2. (2) Violation Severity Levels seem arbitrary and need to be reviewed, considering the standard is giving four years to be 100% complete. The system is presently operating with few if any miss-coordination on these protection systems. (3) There may be different usage of the term 'point of interconnection" in the industry. We suggest the SDT to consider proposing a formal definition of this term. (4) R1.2 states there must be verification of coordination within 90 calendar days following "...identification or implementation..." of systems or changes. There is typically an enormous difference between the "identification" and the "implementation" of these systems. Would the SDT please clarify what is expected? (5) Sister Unit exemptions should be allowed for plants with multiple identical units that have identical equipment and control systems. (6) This Standard should only apply to generators with a nameplate rating of > 75 MVA and a connection to the interconnected transmission grid > 100 kV. (7) The use of "Stead state stability limit" in bullet #4 in R1 and the use of the phrase "...system steady state operating conditions." in R1.1.1, seem to conflict. Is the term in R1 intended to represent system conditions AFTER an N-1 contingency, or during N-0 conditions?
Response: Thank you for your comment. (1) The measure supports evidence needed to demonstrate compliance **(2) The VSL’s are set in accordance with NERC guidelines.** **(3) The applicability section was revised. The phrase, “point of Interconnection” has been deleted.** **(4) SDT intent regard “implementation or identification of changes” is to allow the clock to start when the changes that may occur to equipment capabilities is actually identified (recognizing this awareness may not have been immediately apparent). It is expected changes implemented by the equipment owner are “identified” at the time of implementation.** **(5) Regarding “sister units,” there is minimal burden with verification that the in-service settings are identical (and by extension coordination).** **(6) The applicability section of the standard is based on the Registry criteria, and the SDT does not have sufficient technical justification to deviate**		

Organization	Yes or No	Question 9 Comment
from this criteria. **(7) The standard allows evaluation of N-0 conditions. The equipment owner has discretion to perform evaluation of other conditions.**		
Indeck Energy Services		
Oncor Electric Delivery Company LLC	No	
Indiana Municipal Power Agency	Yes	IMPA does not understand the need to perform the coordination type of study every five years. It should be performed initially and only if something changes that would require a new coordination study. IMPA could see the need to verify the settings on the voltage regulating equipment, etc. just as you would with relay testing but why go through a complete study every 5 years. IMPA recommends performing the coordination study initially as per the timetable listed in the effective dates (section 5) and then again prior to the implementation of systems, equipment, setting changes, etc.IMPA recommends not using the words "verify the existence" in requirement 1.2. This wording is very vague in the sense that it may require just a review of the document to ensure no changes or does it mean that another coordination study needs to be performed. IMPA recommends using the wording "shall review the coordination identified in Requirement R1 at least once every five years or perform the coordination identified in Requirement R1 within 90 calendar days... " if this is the intent of the SDT.
Response: Thank you for your comment. The intent of the five-year verification interval is to verify that settings have not changed. In addition, changes to the transmission system can affect the SSSL. The SDT believes the words "… verify the existence of coordination…" ensures the settings used to evaluate coordination match the in-service settings.		
Los Angeles Department of Water and Power		LADWP does not have a position on this question at this time.
Chelan County PUD	No	

END OF REPORT