NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Generator Verification – Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to MOD-025-2, MOD-027-1 and PRC-019-1. These standards were posted for a 45-day public comment period from February 29, 2012 through April 16, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 57 sets of comments, including comments from approximately 159 different people from approximately 51 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

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 and Director of Standards, Mark Lauby, at 404-446-2560 or at Mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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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	1	2	3	4	5	6	7	8	9	10
1.	Group	David Thorne	Pepco Holdings Inc and Affiliates	X		X							

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
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.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2

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

8.	Chantel Haswell	FPL Group, Inc.	NPCC	5
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Brian Robinson	Utility Services	NPCC	8
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
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	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Valerie Pinamonti	AEP	SPP	1, 3, 5
4.	Michelle Corely	CLECO	SPP	1, 3, 5
5.	Mahmood Safi	OPPD	SPP	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	David Thompson (Chair) ; Joe Spencer (SERC staff)	SERC Generation Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Thompson -chair	TVA	SERC	
2.	Hamid Zakery	Calpine Corp.	SERC	
3.	Tom Higgins	Southern Co.	SERC	

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

4.	Terry Crawley	Southern Co.	SERC	
5.	Bill Shultz	Southern Co.	SERC	
6.	Kumar Mani	Progress Energy	SERC	
7.	Paul Camilletti	Santee Cooper	SERC	
8.	Dale Goodwine	Duke Energy	SERC	
9.	Sam Dwyer	Ameren	SERC	
10.	Joe Spencer	SERC	SERC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	John O'Connor (chair) ; Joe Spencer (SERC staff)	SERC Dynamic Review Subcommittee (DRS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Peng Yu	Entergy	SERC	
2.	Tom Cain	TVA	SERC	
3.	Bobby Jones	Southern Co.	SERC	
4.	Warren Whitson	Southern Co.	SERC	
5.	Robbie Bottoms	TVA	SERC	
6.	Art Brown	Santee Cooper	SERC	
7.	John O'Connor	Progress Energy	SERC	
8.	Rick Foster	Ameren	SERC	
9.	Sharma Kolluri	Entergy	SERC	
10.	Joe Spencer	SERC	SERC	

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Karl	Fraughten	WECC	1
2.	Tanner	Brier	WECC	1, 3, 5, 6
3.	James	Burns	WECC	1
4.	Don	Watkins	WECC	1
5.	John	Haner	WECC	1
6.	Dmitry	Kosterev	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jose Landeros	IID	WECC	1, 3, 4, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
2.	Cathy Breatz	IID	WECC	1, 3, 4, 5, 6
3.	Henryk Olstowski	IID	WECC	1, 3, 4, 5, 6
4.	Christopher Reyes	IID	WECC	1, 3, 4, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	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.	Paul Camilletti	Santee Cooper	SERC	5
3.	Rene Free	Santee Cooper	SERC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	NERC Compliance Policy	NPCC	6
2.	Louis Slade	NERC Compliance Policy	SERC	5
3.	Michael Crowley	Electric Transmission	SERC	1, 3
4.	Sean Iseminger	Fossil & Hydro	SERC	6
5.	Jeff Bailey	Nuclear	MRO	6
6.	Chip Humphrey	Fossil & Hydro	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Chang Choi	Tacoma Power	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Travis Metcalfe	Tacoma Public Utilities	WECC	3
2.	Keith Morisette	Tacoma Public Utilities	WECC	4
3.	Claire Lloyd	Tacoma Public Utilities	WECC	5
4.	Michael Hill	Tacoma Public Utilities	WECC	6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	B. Orians	FE	RFC	5
2.	E. Baznik	FE	RFC	1
3.	K. Dresner	FE	RFC	5
4.	L. Robinson	FE	RFC	5
5.	M. McLean	FE	RFC	1
6.	D. Hohlbaugh	FE	RFC	
7.	L. Raczkowski	FE	RFC	

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	James Manning	NC Electric Membership Corporation	SERC	1
3.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
4.	Philip Kleckley	SC Electric & Gas Company	SERC	1
5.	Pat Huntley	SERC Reliability Corporation	SERC	10
6.	Bob Jones	Southern Company Services	SERC	1
7.	Darrin Church	TVA	SERC	1

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

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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Heimbach	PPL EnergyPlus, LLC	MRO	6
2.	Annette Bannon	PPL Generation for its NERC Registered Entities	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15. Group	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				

No additional members listed.

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5
2.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
3.	Mohan Sachdeva	Buckeye Power	RFC	3, 4
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Tom Flynn	Puget Sound Energy					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Denise Lietz	Puget Sound Energy	WECC	1
2.	Erin Apperson	Puget Sound Energy	WECC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Steve Rueckert	Western Electricity Coordinating Council										X

No additional members listed.

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Individual	David Thompson	Tennessee Valley Authority - GO/GOP	X		X		X	X				
20.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
21.	Individual	Antonio Grayson	Southern Company	X		X		X	X				
22.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
23.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
24.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				
25.	Individual	Dan Roethemeyer	Dynegy					X					
26.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
27.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	S. Tekala	SRP	X				X				X	
32.	Individual	John Seelke	Public Service Enterprise Group (PSEG)	X		X		X					
33.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
34.	Individual	David Youngblood	Luminant Power					X					
35.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
36.	Individual	Jack Stamper	Public Utility District No. 1 of Clark County	X									
37.	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
38.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
39.	Individual	Anthony Jablonski	ReliabilityFirst										X

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Kathleen Goodman	ISO New England Inc.		X								
42.	Individual	Mark B Thompson	Alberta Electric System Operator		X								
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company	X									
44.	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
45.	Individual	Dennis Sismaet	Seattle City Light						X				
46.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
47.	Individual	Thad Ness	American Electric Power	X		X		X	X				
48.	Individual	John Bee	Exelon	X		X		X					
49.	Individual	Don Jones	Texas Reliability Entity										X
50.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
51.	Individual	Matthew Pacobit	AECI					X					
52.	Individual	Randall McCamish	City of Vero	X		X							
53.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
54.	Individual	Michael Goggin	American Wind Energy Association								X		
55.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
56.	Individual	Ken Wofford	Georgia Transmission Corporation	X									
57.	Individual	Michael Gammon	Kansas City Power & Light										

MOD-025 Overall Summary Consideration: Stakeholders provided many suggestions for improvements to the language of the standard.

The majority of stakeholders agree with splitting the requirements as noted in the revised standard. The majority of the comments appear to be caused by confusion concerning what exactly is meant by separate testing as stated in Attachment 1. This seems to be caused by the fact that the Reactive Power verification requires Reactive Power data to be taken at several different Real Power operating levels. The intent of the standard drafting team is to allow verification of Real and Reactive Power at the same time if desired by the Generator Owner. This is not required. If the generator owner desires, they may do the two verifications at separate time. It is the opinion of the drafting team that since one of the operating points required for the Reactive Power verification is one with the Real Power output at the expected maximum, that it would be a simple and efficient method to use that operating point as the Real Power verification also.

The majority of commenters agree with the applicability to synchronous condensers greater than 20 MVA. Some commenters suggested that Synchronous Condensers do not have a full capability curve and therefore, do not need to be tested at four points. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous generators. We have added Note 5 to Attachment 1 to clarify this:

> **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**

A couple of stakeholders suggested having the applicability threshold increase from 20 MVA to 100 MVA. The GVSDT respectfully disagrees with regard to the 20 MVA threshold and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.

Most stakeholders agree with having the verification data submitted to the Transmission Planner. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator, Balancing Authority or Planning Authority (Coordinator). As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

  c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with which continues to require the data be submitted to the Transmission Planner.

Several stakeholders disagree with the use of "bulk power system" in the applicability. The GVSDT has revised this to use the term "Bulk Electric System" instead. Concerns were raised regarding the verification schedule for entities that own five or fewer units. The GVSDT removed Sections 5.1.1 and 5.2.1. Entities that own one unit will be required to verify their unit within two years. Entities that own two units will be required to verify one unit within two years and both units within three years.

The GVSDT received several comments regarding the language in Attachment 1. As a result the GVSDT restructured item 2 of Attachment 1:

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the

threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

Some commenters had questions regarding Section 5.3 regarding wind farms. The GVSDT acknowledges that this statement was placed in the standard as an explanation and is not appropriate to be included as section 5.3. This information was expanded and included as a footnote rather than section 5.3:

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

1. The GV SDT has revised MOD-025-2 by splitting Requirement R1 into two requirements that allow for separate testing for real and reactive power. A paragraph was added to the start of Attachment 1 that further explains this point. Do you agree with this revision? If not, please explain in the comment area below.

Summary Consideration: The majority of stakeholders agree with splitting the requirements as noted in the revised standard. The majority of the comments appear to be caused by confusion concerning what exactly is meant by separate testing as stated in Attachment 1. This seems to be caused by the fact that the Reactive Power verification requires Reactive Power data to be taken at several different Real Power operating levels. The intent of the standard drafting team is to allow verification of Real and Reactive Power at the same time if desired by the Generator Owner. This is not required. If the generator owner desires, they may do the two verifications at separate time. It is the opinion of the drafting team that since one of the operating points required for the Reactive Power verification is one with the Real Power output at the expected maximum, that it would be a simple and efficient method to use that operating point as the Real Power verification also.

Organization	Yes or No	Question 1 Comment
Southwest Transmission Cooperative, Inc.	Negative	1. While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient. 2. What if a wind farm has more than two sites? Why is it specific to a single technology?

Organization	Yes or No	Question 1 Comment
		3. We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. 4. We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. 5. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to be only the latest verification or does it include the last verification? Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the “Periodicity for conducting a new verification” section. A close reading of the two items shows they are identical but listed separately to make the statement about listing

Organization	Yes or No	Question 1 Comment
		the "earliest date of those dates" for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the "Verification specifications for applicable Facilities:" section. If operational data can be used to satisfactorily verify the unit's real and reactive power output, it should always be allowed to avoid the need for a staged test.

Response: The GVSDT thanks you for your comment.

1. **Sections R1.1.1 and R2.2.1 require that the verifications be performed and sections R1.1.2 and R2.2.2 require that the data be reported within 90 days of the date the verification is performed if for a staged test, or the date that the data is selected if the GO is utilizing operational data. The requirement is written in this way to allow the GP the flexibility of choosing either operational data (the actual date of collection of this operational data may be in the past, hence the requirement to report it within 90 days of the date of SELECTION of the data) or to stage a specific test to meet the requirement. If a GO decides to use two separate operational data points for the real and reactive verifications, then each attachment 2 might have some blank spots. The Attachment 2 is only a convenience for reporting, and GOs are free to use any form that captures the same information. If one is performing real power verification, then reactive power would not be reported. If one is performing a reactive power test, one must record more than one point. These points are defined by both real and reactive power, so both must be recorded. Again, the language was specifically crafted to allow the GO to perform both verifications at the same time if they choose, but this is not required. If a GO chooses to perform the verifications together, at the same time, then a single Attachment 2 is sufficient for both.**
2. **Wind Farms are a unique situation for compliance with MOD-025. The intent of Section 5.3 was to add clarity and provide an example of how to assess compliance for wind farms. The GVSDT has removed this section and added a footnote to clarify the issue further.**

    [1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Organization	Yes or No	Question 1 Comment
3. The standard is applicable to Synchronous Condensers greater than 20 MVA because they are important reactive resources. These are devices that normally operate as synchronous condensers, so they are not operating in an emergency mode. Perhaps the commenter refers to certain hydro units that can be operated at 0 power factor. These would not be considered synchronous condensers under the standard. 4. The drafting team appreciates your comment, as many members are aware of the situation you cite. The team cannot predict the behavior of auditors. The last verifications date column was added to avoid potential confusion with the use of operational data. When operational data is used, the last verification date may not match the date the operational data was selected and submitted, thus the information was added to simplify the determination of periodicity. 5. We do not see a conflict. The requirement simply states that the data must be SUBMITTED within 90 days of either a staged test or the date that operational data was SELECTED. The attachment informs entities that operational data can come from within a two year period prior to the verification date. The verification date for verification by operational data is the date that the operational data was SELECTED, not the date that the operational data was recorded. The GVSDT recognizes that the language is somewhat complex, however, it is the best we have that still allows the flexibility to use either operational data or a staged test. The GVSDT would welcome specific suggestions for improved language that preserves this intent. The language in Attachment 1 section 2 requires that the first test be a staged test. This is intended to prevent the use of operational data points that do not validate at least 50% of the associated D curve capability from being used as the benchmark for future verifications. Once an initial staged test to the appropriate level is completed, use of operational data going forward is allowed.		
Luminant Energy	Negative	See comments submitted by Luminant Energy. VOTE NO based on the extensive comments made that deleted items in Attachment 1 and 2.
Response: The GVSDT thanks you for your comment. Please see the response to Luminant Energy's comments.		
Northeast Power Coordinating Council	No	1. Attachment 1 requires a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% that is expected to last more than 6 months within 12 months. This is an excessive period of time for a generator to be providing less than expected Real or Reactive power output.

Organization	Yes or No	Question 1 Comment
		2. Also, Attachment 1 requires staged verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.). 3. The data requested in this Standard will verify a generator's capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data for both under-excited and over-excited field conditions will result in 4 specific data points that can assist TP's in system studies. The GO can obtain this data by planning on doing the maximum lagging and leading tests when system conditions allow to measure the 4 specific data points desired. 4. "Separate tests" are not explained except for the statement "separate testing is allowed for this standard" which is in Attachment 1. What constitutes "separate testing"?

Response: The GVSDT thanks you for your comment.

1. The GVSDT does not feel that this is excessive. The planning function is typically performed on an annual basis. There are real time operating reporting requirements for short term issues

2. The standard requires verification every 5 years. The first verification must be by a staged test, subsequent verifications can be either by staged test or reporting of operational data.

3. As the commenter notes, the standard requires Reactive Power Verification at different points. The required Real Power levels are part of the Reactive Power verification. This is why the standard allows Generator Owners to perform both Real and

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Reactive Power verification at the same time if they choose. It does not require that both be performed at the same time, primarily to allow maximum flexibility in the case of verification by operational data. If one performs the Reactive Power verification by itself, one must still reach the required Real Power operating points as described in the Attachment 1 section 2, so there is no harm in performing the test separately. There is a significant level of experience performing these tests among the members of the drafting team. It is not always possible to reach the D curve levels due to various conditions not related to the generating equipment performance, and for this reason there is no requirement to reach the D curve rating. The standard requires that the verification be performed to the level allowed by system conditions.

4. Separate testing is the performance of the real and reactive verifications at different time. It is allowed, but not required.</td></tr>
<tr><td>PPL</td><td>No</td><td>Suggest changing “Intended” to “preferred” in the Att. 1 statement, “It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard.”</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT sees no difference from a reliability standpoint in performing the two tests together or separately, since the same data is collected. One is not preferred over the other, and we stand by the word intended because it is more time efficient to do both together.</td></tr>
<tr><td>ACES Power Standards Collaborators</td><td>No</td><td>While we agree with the intent, we believe that Parts 1.2 and 2.2 collectively limit the tests to be no further than 90 days apart. Both parts state that Attachment 2 or another form that contains the same information must be completed within 90 calendar days of the staged test or date the operational data is selected. Since both have real and reactive power entries, can the form be considered completed without both sets of data? If the SDT intends for these real and reactive power tests to be completed greater 90 days apart, some additional clarification needs to be made to Part 1.2 and 2.2. Perhaps a note at the beginning of Attachment 2 explaining that MVAr will not be completed for a real power test and MVA will not be completed for a reactive power test will be sufficient.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The Reactive Power test requires Real Power data also. The Real Power</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
test does not require Reactive Power Data. The Real Power and Reactive Power tests may have different verification dates, so the GVSDT does not believe that the requirement limits them to be no more than 90 days apart. The data must only be reported within 90 days of the verification.		
Consolidated Edison Co. of NY, Inc.	No	o The data requested in this Standard will verify a generators capability curve. Standards FAC-008, FAC-009, and IRO-010 already require TOs and GOs to develop facility ratings for real power (net and gross) and reactive power (gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. Therefore, MOD-025 should stipulate that testing of MW and MVAR be performed at the same time (not separately) to verify the 4 applicable data points. As per Attachment 2, full load and minimum load data both under and over excited field conditions will result in 4 specific data points that can assist TP's in system studies. For example, the GO can obtain this data by: o The maximum lagging and then leading test at full load may be performed during a high load day to obtain two data points. o The maximum lagging and then leading test at minimum load may be performed during the evening to two data points. o We could not find a paragraph explaining separate tests except for the statement "separate testing is allowed for this standard". So no, we don't agree with this revision. Attachment 1 requires verification every 5 years. Verifying the generator capability curve is only required once, or whenever the generator equipment has been modified (i.e. new exciter, stator rewind, etc.).
Response: The GVSDT thanks you for your comment. Please see the response to the Northeast Power Coordinating Council comments.		
SRP	No	Real Power tests were performed at the same time as Laod Reactive Power testing in the past and plotted on the generator"s capability curves. What would be gained by conducting two separate tests?

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. Two separate tests are not required, it is allowed if desired by the Generator Owner.</td></tr>
<tr><td>Public Service Enterprise Group (PSEG)</td><td>No</td><td>In splitting R1 into two requirements, the R2 erroneously refers to “Real Power”; this should be “Reactive Power.”

The first sentence in added paragraph Attachment 1 regarding separate testing of Real and Reactive Power testing should be rewritten. The term “Load” as used does not conform to the Glossary definition of “Load,” which is “An end-use device or customer that receives power from the electric system.”

The only combined testing on Real and Reactive Power applies to sections 2.1 and 2.2 in Attachment 1 where Real Power is tested. Therefore, the added sentence should be rewritten as follows: “It is intended that Real Power testing in sections 2.1 and 2.2 be performed at the same time as Reactive Power testing; however separate testing is allowed for this standard.”</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The commenter is correct that R2 should refer to Reactive Power, the error will be corrected.

The GVSDT agrees, and the word ‘Load’ will be eliminated and replaced with “Real Power”.</td></tr>
<tr><td>ISO New England Inc.</td><td>No</td><td>Attachment 1 does not require a generator to notify the Transmission Planner of a change in Real or Reactive Power capability of greater than 10% for up to 12 months. This is too long a period for a generator to be providing less than expected power output.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The time period is consistent with the planning function, which is typically performed on an annual basis. The real time operating standards already require more immediate reporting of unit limitations.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
TransAlta Centralia Generation LLC	No	Do not agree to Attachment 1 item 2.2 and 2.3. Refer comments below: 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Typically, the maximum overexcited and under-excited reactive capability is tested at the Rated or full Real Power output of generator, not at the minimum Real Power output of generator. 2.3. Conduct the maximum Real Power and over-excited Reactive Power verifications required in 2.1 for a minimum of one continuous hour. Please verify the reason for a minimum of one continuous hour.
Response: The GVSDT thanks you for your comment, but is unable to respond since you have not provided any information on what you don't agree with in Attachment 1 2.2 and 2.3 or why.		
Seattle City Light	No	Attachment 1 "Periodicity for conducting a new verification:" Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years.
Response: The GVSDT thanks you for your comment. The drafting team felt that 5 years was appropriate for this standard in order to catch any equipment issues that might develop. The longer periodicity for MOD-026 and MOD-027 reflects the greater complexity involved with performing those verifications.		
AECI	No	I believe that a one continuous hour test for reactive testing will not increase reliability. Most units are not used for long periods of time for reactive power. I am also worried about damage due to High winding temperatures during this test.
Response: The GVSDT thanks you for your comment. There is no requirement to exceed any generating unit limits, such as winding temperatures, during the verifications. One continuous hour was established as a minimum time for verification that		

Organization	Yes or No	Question 1 Comment
there are no equipment related issues with operating at the verification levels.		
Seattle City Light	No	Attachment 1 “Periodicity for conducting a new verification:” Frequency of tests should correlate better with MOD-026 and MOD-027, which is once every 10 years.
Response: The GVSDT thanks you for your comment. The drafting team felt that 5 years was appropriate for this standard in order to catch any equipment issues that might develop. The longer periodicity for MOD-026 and MOD-027 reflects the greater complexity involved with performing those verifications.		
City of Vero	No	
Dominion- NERC Compliance Policy	Yes	Dominion agrees with splitting Requirement R1; but notes that Requirement R2 should be changed from “Real Power Capability” to “Reactive Power Capability.” Additionally, Requirement R3 should be changed from “Real Power Capability” to “Reactive Power Capability.”
Response: The GVSDT thanks you for your comment. You are correct and the standard has been updated to show the corrections.		
SERC Generation Subcommittee	Yes	However, see our response to Question #4.
Response: The GVSDT thanks you for your comment. Please see responses to question 4.		
Southern Company	Yes	a) The method of reactive power capability determination described in "Note 2" of Attachment 1 should be included as an allowable third (3rd) method of reactive power capability verification. (as an alternative to using operational data or staged testing) b) Any verification specifications listed on Attachment 1 that merely repeat the line items of data requirements shown on Attachment 2 should be eliminated - they are not necessary in both locations.

Organization	Yes or No	Question 1 Comment
Response: The GVSDT thanks you for your comment. a)The GVSDT does not believe that calculations are an appropriate method of verification as they do not show anything about equipment condition or prove that equipment will work as designed. b) The GVSDT believes that this adds clarity, and represents very little additional effort.		
Ingleside Cogeneration LP	Yes	Even if the requirements are somewhat redundant, there are a number of important differences between Real and Reactive Power validations. In addition, there is a need to allow Generator Owners to address each separately if they should so choose. For example, a Real Power validation may be easily handled through actual operations data, while Reactive Power validations may need coordinated testing with the interconnected Transmission Operator. Under a single requirement, there is a risk that Compliance Authorities will assume that every test must be performed at the same time - using the same method.
Response: The GVSDT agrees and thanks you for your comment.		
Wisconsin Electric Power Company	Yes	Requirements R1.2 and R2.2 have data submittal dates for Real and Reactive Power verification values. The required timeframe of “90 calendar days” needs to be clarified when using historical operating data. For example, if a date of 180 days ago is selected for the verification, how can the data be required within 90 calendar days? The due date for a verification using historical data does not seem very meaningful.
Response: The GVSDT thanks you for your comment. The GVSDT agrees, and that is why the standard states in the requirements that the verification date for operational data verifications is the date that the operational data is SELECTED, not the date the operational data was RECORDED.		
Texas Reliability Entity	Yes	R1.2 - We suggest removing the phrase “date the data is recorded for a” and replace with “date of a”. It is not important to note the date on which the data is “recorded” but rather the date a staged test occurred. “Recorded”

Organization	Yes or No	Question 1 Comment
		could have different meanings - is it “recorded” when a Verification Data form or report is finalized internally or when PI Historian captures the SCADA data? Remove “or a form containing the same information as identified in Attachment 2” and change the verbiage on Form 2 (“changes may be made to this form”). If there is a form, require its use to promote consistency. Additional forms can be provided by the TP if needed to cover additional configurations.
Response: The GVSDT thanks you for your comment. The GVSDT believe that language is clear, and that the two situations that you note are differentiated by the fact that the word ‘submitted’ is used to describe when the data is sent to the Transmission Planner, the word ‘recorded’ describes when the staged test data is taken. Further, the word ‘Selected’ is used to describe the date that operational test data is chosen for us as verification data. Attachment 1 states that this operational data may come from anywhere in the two year period prior to its selection date.		
Duke Energy	Yes	However, see our response to Question #4.
Response: The GVSDT thanks you for your comment. Please see response to question 4.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
SERC Dynamic Review Subcommittee (DRS)	Yes	
Bonneville Power Administration	Yes	
Imperial Irrigation District (IID)	Yes	

Organization	Yes or No	Question 1 Comment
Santee Cooper	Yes	
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Ameren	Yes	
Oncor Electric Delivery Company	Yes	
Cowlitz County PUD	Yes	
American Electric Power	Yes	
Exelon	Yes	
Entergy Services, Inc	Yes	
American Wind Energy Association	Yes	
Indiana Municipal Power Agency	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc and Affiliates		No comment

2. The GV SDT clarified the applicability of this standard to synchronous condensers greater than 20 MVA (nameplate rating). Do you agree with this applicability? If not, please explain in the comment area below.

Summary Consideration: The majority of commenters agree with the applicability to synchronous condensers greater than 20 MVA.

Some commenters suggested that Synchronous Condensers do not have a full capability curve and therefore, do not need to be tested at four points. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous generators. We have added Note 5 to Attachment 1 to clarify this:

> **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**

A couple of stakeholders suggested having the threshold increase from 20 MVA to 100 MVA. The GVSDT respectfully disagrees with regard to the 20 MVA cut-off and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.

Other stakeholders disagreed with the applicability section referencing the "bulk power system." The GVSDT agrees and revised this to reference "Bulk Electric System."

Organization	Yes or No	Question 2 Comment
City of Green Cove Springs	Negative	Applicable Facilities could be simply those that are not Black-Start., simplifying the language considerably
Response: The GVSDT thanks you for your comment. The GVSDT believes that by simply saying "those that are not Black Start" in the Applicability/Facilities section that synchronous condensers would be excluded and smaller facilities that were not intended would be included. There was overwhelming support on the last posting to include synchronous condensers to this standard.		
Southwest Transmission Cooperative, Inc.	Negative	While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability. We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under

Organization	Yes or No	Question 2 Comment
		criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations.
Response: The GVSDT thanks you for your comment. The GV SDT removed blackstart units from the standard in the previous posting.		
Pepco Holdings Inc and Affiliates	No	Agree with the generating unit nameplate thresholds as defined in this standard and the compliance registry, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the

Organization	Yes or No	Question 2 Comment
		applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term "bulk power system" and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition. Of course, Synchronous condensers are not spelled out either in the Compliance Registry, or the BES definition, and therefore they will have to be addresses separately in 4.2.2 as "Individual Synchronous Condensers greater than 20MVA (gross nameplate rating) directly connected at the point of interconnection at 100kV or above. "
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced "bulk power system" with the defined term "BES".		
Northeast Power Coordinating Council	No	The data requested in this Standard will verify a generator's capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, synchronous condensers should be removed from MOD-025.
Consolidated Edison Co. of NY, Inc.	No	The data requested in this Standard will verify a generators capability curve. Synchronous Condensers do not have a capability curve but a maximum and lag and lead rating which are established and communicated in NERC Standards IRO-010, FAC-008 and FAC-009. Therefore, we recommend that synchronous condensers be removed from MOD-025.
Response: The GVSDT thanks you for your comment. While the GVSDT agrees that synchronous condensers do not have a typical capability curve, nor do they need one, a verification of the capability is needed similar to the verification of synchronous		

Organization	Yes or No	Question 2 Comment
generators. We have added Note 5 to Attachment 1 to clarify this: **"Note 5: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output."**		
SERC Generation Subcommittee	No	Clarification should be made on applicability. Does this apply only to stand-alone synchronous condensers, or are hydro units, that can be used in condensing mode, also included? Also, we believe that the 20 MVA cut-off rating is too low for this standard. We would suggest that the same threshold used in MOD 26 and 27 (100 MVA), be used. If necessary, the regions can set more restrictive thresholds.
Santee Cooper	No	Clarification should be made on applicability. Does this apply only to stand alone synchronous condensers, or are hydro units that can be used in condensing modes, also included. Also, we believe that the 20 MVA rating is too low for this standard. We would suggest that the same threshold as used in MOD 26 and 27 (100 MVA) be used. If necessary, the regions can set more restrictive thresholds.
Response: The GVSDT thanks you for your comment. The standard applies to both stand alone synchronous condensers and hydro units that can be used in condensing modes. The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator. The GVSDT respectfully disagrees with regard to the 20 MVA threshold and believes that the same MVA threshold used for reactive capability of synchronous generators should apply to synchronous condensers.		
SERC Dynamic Review Subcommittee (DRS)	No	In some cases there is no benefit to require testing of smaller units. The DRS recommends that units with nameplate ratings at or below 100 MVA (consistent with the MOD-027-1) be exempted from testing upon mutual agreement between the GO and Transmission Planner.
Response: The GVSDT thanks you for your comment. Due to the localized nature of voltage control the GVSDT feels it would be a mistake to classify Reactive Power testing the same as the Active Power/Frequency Control functions included in MOD-027-1. The		

Organization	Yes or No	Question 2 Comment
GVSDT does not have sufficient evidence to exempt generators that are included in the NERC Registry Criteria nor do we believe it is appropriate to exclude them.		
Florida Municipal Power Agency	No	FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that:BPS = BES + (protection and control systems covered by the standards)To parallel the Section 215 definition of BPS at (a)(1)"The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..."We have not heard from the BES definition team yet whether they will address this issue.A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element".To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn't already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.

Organization	Yes or No	Question 2 Comment
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced references to "bulk power system" with the NERC defined term BES. The SDT disagrees that a synchronous condenser is a generator and the Transmission Owner could be removed from the Applicability because a significant number of synchronous condensers are owned by the Transmission Owner, not the Generator Owner.		
Transmission Access Policy Study Group	No	The SDT states that it "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." TAPS agrees that the standard should be consistent with the BES definition. Given that the MVA limits in the BES definition (and the Registry Criteria) may change, TAPS believes that the standard should not contain numerical limits. Moreover, the standard should be based on the BES definition, which delineates the elements subject to Reliability Standards, rather than on the Statement of Compliance Registry Criteria, which instead defines the entities that must comply with Reliability Standards. We believe that the SDT's concern about synchronous condensers can also be addressed more effectively without incorporating text from the current Registry Criteria. TAPS therefore suggests that the Applicable Facilities section be revised as follows: "For the purpose of this standard, the term, 'applicable Facility' shall mean 'BES generator,' except that a generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard. For the purpose of this standard, a synchronous condenser is treated as a generator."
Response: The GVSDT thanks you for your comment. The GVSDT at one point referred to the applicable units simply by those included in the Registry Criteria but was directed by NERC to state the numerical limits. If in the case where the BES definition or Registry Criteria definitions change, the" Applicability" can be reviewed and updated as necessary during the next standard revision.		
ACES Power Standards Collaborators	No	While we agree to limit the inclusion of synchronous condensers to 20 MVA, we disagree with two other aspects of the applicability.

Organization	Yes or No	Question 2 Comment
		1) We disagree with inclusion of Blackstart Resources and applicability to the bulk power system. Blackstart Resources should not be included within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, the purpose of their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during the restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. 2) The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: "The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system." Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete,

Organization	Yes or No	Question 2 Comment
		confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. 3) We also find section 5.3 regarding wind farm verification confusing. What is its purpose? What if a wind farm has more than two sites? Why is it specific to a single technology?
Response: The GVSDT thanks you for your comment. **1) The SDT removed blackstart units from this standard in the previous posting.** **2) The SDT has replaced "bulk power system" with the defined term "BES".** **3) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:** **1 Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.**		
Southern Company	No	a) The applicability threshold is too small. Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. b) We feel that machines able to run either as a synchronous condenser as well as a synchronous generator need only be validated in generator mode. It is unclear if the requirement for synchronous condensers is for machines with a single mode of operation. c) The individual unit size criterion value should equal the gross aggregate plant/ Facility threshold value.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 2 Comment
a) MOD-026-1 and MOD-027-1 verify models. PRC-019 coordinates limiters with protection and machine capabilities. MOD-025-1 verifies Real and Reactive capabilities. Although loosely related the purpose of each of these standards is different. The potential for stated capability to be different from the capability that can be verified is large. With this in mind, the GVSDT has no basis to exclude generators that are included in the Registry Criteria nor do we believe it is appropriate to do so. **b) The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator.** **c) Changing the unit size criterion to make value to equal the gross aggregate plant/facility threshold value would effectively exempt a large portion of generation (all wind farms would be exempted for example). The GVSDT has no basis to exempt this much generation.**		
ExxonMobil Research and Engineering	No	The SDT should clarify that a Synchronous Condenser is not a Synchronous Motor. Synchronous condensers are operated to provide Voltage Support to the bulk electric system through the production of VARS. A Synchronous Motor is theoretically the same piece of equipment with one exception; in a modern industrial electric distribution system, a Synchronous Motor's purpose is to drive a mechanical load while remaining VAR neutral (or closes to it). As written, industrial facilities that are registered as Generator Owners and operate large Synchronous Motors may be required to comply with this standard and be unable to comply with this standard due to the nature of the equipment that operates the Synchronous Motor's excitation system.
Response: The GVSDT thanks you for your comment. The GVSDT believes that a synchronous condenser and a synchronous motor are synchronous machines that are used for two different purposes. We believe this purpose is clear and there will be no confusion that the standard is applicable to synchronous condensers and not synchronous motors. It is believed that there are no synchronous motors (with the exception of those motor/generators used in pumped storage facilities) that are directly connected to the BES and they would, therefore, not be included in the applicability for MOD-025-2.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes that MOD-025-2 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since

Organization	Yes or No	Question 2 Comment
		synchronous condensers are not part of those criteria, they should be 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 - and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of the BES takes effect.
Response: The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers during the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2."		
Public Service Enterprise Group (PSEG)	No	In the Background material on the Comment form for MOD-026-2 and PRC-024-2, the following statement is included for MOD-026-2:"The GVSDT asked stakeholders if they believed that synchronous condensers should be applicable under MOD-026. The majority of commenters believe that synchronous condensers should not be included in MOD-026. Synchronous condensers are not currently addressed in the NERC Registry Criteria. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low, with many units owned by Transmission Owners. As such, the peer review draft requirements would not make sense. The SDT decided that, with the current structure of the Compliance Registry Criteria, if there is a need to develop a reliability standard to model the expected behavior of dynamic voltage devices typically owned by Transmission entities, then a more appropriate strategy is to include synchronous condensers along with other Transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) into a separate SAR. The GVSDT will closely monitor BES SDT efforts to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria, and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of synchronous condensers."If synchronous condensers are

Organization	Yes or No	Question 2 Comment
		not currently addressed in the NERC Registry Criteria, they should not be included in the either MOD-025-2 or PRC-019-1.
Response: The GVSDT thanks you for your comment. There was overwhelming industry support (approximately 96%) for inclusion of synchronous condensers at the first posting of MOD-025-2. The Definition of Bulk Electric System (BOT Adoption Jan 2012) includes in "I5 – Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher, or through a transformer that is designated in Inclusion I2."		
City of Vero	No	FMPA Agrees with the 20 MVA bright line for synchronous condensers but disagrees with the way in which it was implemented. The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards)To parallel the Section 215 definition of BPS at (a)(1)"The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..."We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". To handle synchronous condensers, the 20 MVA bright line can be achieved by simply making it clear that a synchronous condenser is a generator covered under a Generator Owner and Operator registration. It seems the SDT

Organization	Yes or No	Question 2 Comment
		wanted to add flexibility that a synchronous condenser could be covered by either a TO or GO registration; however, there is nothing that a GO has to do in the standards that a TO doesn't already have to do except VAR-002, which should be done for a synchronous condenser anyway and that flexibility is not necessary. This would also enable eliminating the TO from the standard.
Response: The GVSDT thanks you for your comment. The SDT agrees and has replaced references to "bulk power system" with the NERC defined term BES. The SDT disagrees that a synchronous condenser is a generator and the Transmission Owner could be removed from the Applicability because a significant number of synchronous condensers are owned by the Transmission Owner, not the Generator Owner.		
Texas Reliability Entity	Yes	Attachment 1, item 3.2: Is there a requirement for a voltage schedule for a synchronous condenser? Also, if there is a modified voltage schedule to accommodate the testing, the normal voltage schedule and modified voltage schedule should be recorded. Attachment 2 does not necessarily include Synchronous Condensers.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has added the words "if applicable" to item 3.2. While Attachment 2 does not necessarily include synchronous condensers it does not exclude them either. The GVSDT has revised Attachment 2 to specifically include synchronous condensers.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
PPL	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
Cowlitz County PUD	Yes	
American Electric Power	Yes	
Exelon	Yes	

Organization	Yes or No	Question 2 Comment
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Kansas City Power & Light	Yes	
Imperial Irrigation District (IID)		Not applicable to IID - abstained
Indiana Municipal Power Agency		no comment

3. **The GV SDT clarified that the data is to be submitted to the Transmission Planner by the Generator Owner or Transmission Owner. Do you agree with this? If not, please explain in the comment area below.**

Summary Consideration: Most stakeholders agree with having the verification data submitted to the Transmission Planner. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator, Balancing Authority or Planning Authority (Coordinator). As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers.

The GVSDT has not revised the requirement with which continues to require the data be submitted to the Transmission Planner.

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery	Negative	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.
Oncor Electric Delivery Company	No	In a deregulated market, the Balancing Authority (BA) and Planning Authority (PA) are in the best position to provide a more strategic look at gathering this type of information and ensuring the necessary broad distribution. As a result, the receiving and requesting of modeling data from a Generator Owner (GO) should be the responsibility of the PA or the BA and not the Transmission Planner. This approach provides a single clearinghouse for generator data, ensuring accuracy and consistency, to and from the GO which then can accessed by any impacted Registered Entities.

Response: The GVSDT thanks you for your comment. Please see Summary Consideration for question 2 from the previous posting. That response states in part: “Most stakeholders suggested that the Transmission Planner is the appropriate entity to receive the data required by MOD-025-1. A few commenters suggested that the information should be provided to other reliability entities such as the Reliability Coordinator. As this is a long-term planning standard, it is envisioned that the TP receives the data and develops the appropriate models for use by other entities. The TP then hands these models off to entities that are concerned with the Operations planning and Real-time Operations time horizons. Per the NERC Reliability Functional Model (v5, page 25), the Transmission Planner has the following relationships with other entities:

2. Collects information including:

c. Generator unit performance characteristics and capabilities from Generator Owners.

5. Coordinates the evaluation of Bulk Electric System expansion plans with Transmission Service Providers, Transmission Owners, Reliability Coordinators, Resource Planners, and other Transmission Planners.

Organization	Yes or No	Question 3 Comment
6. Reports on and coordinates its Bulk Electric System expansion plan implementation with affected Planning Coordinators, Transmission Planners, Resource Planners, Transmission Service Providers, Transmission Owners, Transmission Operators and Reliability Assurers. **The GVSDT has not revised the requirement with respect to submitting the data to the Transmission Planner. The requirement continues to require the data be submitted to the Transmission Planner."**		
Northeast Power Coordinating Council	No	The Reliability Coordinator is the entity that should receive this data. There are instances where a number of entities are registered as Transmission Planners. To avoid confusion this data should be submitted to a single entity who will then distribute the data. Transmission Planner should be added to the Applicability Section 4.1 Functional Entities.
Response: The GVSDT thanks you for your comment. The GVSDT believes that since the Transmission Planner does not have any actions under the standard except receiving the data, addition of the Transmission Planner is not needed. An overwhelming majority of the commenters concurred with the Transmission Planner as the entity to receive the data and therefore, the GVSDT does not propose a change.		
Public Service Enterprise Group (PSEG)	No	Transmission Operators should also be provided the data.
Response: The GVSDT thanks you for your comment. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Transmission Operators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
ISO New England Inc.	No	We feel that the Reliability Coordinator is the appropriate entity to receive this data. In our area a number of entities are registered as Transmission Planners, to avoid confusion this data should be submitted to a single entity who will then distribute the data.

Organization	Yes or No	Question 3 Comment
Response: The GVSDT thanks you for your comment. An overwhelming majority of the commenters concurred with the Transmission Planner as the entity to receive the data and therefore, the GVSDT does not propose a change. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Reliability Coordinators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
TransAlta Centralia Generation LLC	No	In some cases, the data at the interconnection point (such as the high side of generator step-up transformer) may not come directly from GO as the measuring instrumentation may not be owned by the GO
Response: The GVSDT thanks you for your comment. Since the bulk of the information (and in many cases all of the information) needed comes directly from the GO, the GVSDT believes that the GO is the correct entity to obtain the data. If data from another company is required, the GVSDT believes that it should be available to the GO.		
SERC Dynamic Review Subcommittee (DRS)	Yes	The Transmission Planner is in the best position to determine the impact of the results on long term system reliability. Additionally, the Transmission Planner is often the entity that provides this data to other entities (via the MMWG process) for modeling and simulation purposes.
Response: The GVSDT thanks you for your comment.		
Bonneville Power Administration	Yes	BPA believes that the applicability from PRC-19-1, 4.1.2 “Transmission Owner that owns synchronous condenser(s)”, should also be applied to the applicability of MOD-025-2 with respect to Transmission Owners.
Response: The GVSDT thanks you for your comment. Although the applicability does not change, the wording has been modified to match PRC-019-1, 4.1.2 for consistency.		
Florida Municipal Power Agency	Yes	See comments to question 2
Response: The GVSDT thanks you for your comment. See response to question 2.		

Organization	Yes or No	Question 3 Comment
Consolidated Edison Co. of NY, Inc.	Yes	Please add the TP in the Functional Entities in section 4.1.
Response: The GVSDT thanks you for your comment. The GVSDT believes that since the Transmission Planner does not have any actions under the standard except receiving the data, addition of the Transmission Planner is not needed.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the proper recipient is the Transmission Planner. There is no reliability reason that we are aware of to include Transmission Owner in the loop - as the previous version of MOD-025-2 called for.
Response: The GVSDT thanks you for your comment.		
City of Vero	Yes	See comments to question 2
Response: The GVSDT thanks you for your comment. See response to question 2.		
Tacoma Power	Yes	None
Southwest Power Pool Standards Development Team	Yes	
SERC Generation Subcommittee	Yes	
Imperial Irrigation District (IID)	Yes	
Santee Cooper	Yes	
Dominion- NERC Compliance Policy	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
SERC Planning Standards Subcommittee	Yes	
PPL	Yes	
ACES Power Standards Collaborators	Yes	
Puget Sound Energy	Yes	
Western Electricity Coordinating Council	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and	Yes	

Organization	Yes or No	Question 3 Comment
Gas		
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Wisconsin Electric Power Company	Yes	
Ameren	Yes	
Seattle City Light	Yes	
Cowlitz County PUD	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Georgia Transmission Corporation	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
Pepco Holdings Inc and Affiliates		No comment
Indiana Municipal Power Agency		no comment

4. **Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-025-2?**

Summary Consideration: Stakeholders provided many suggestions for improvements to the language of the standard. Several stakeholders disagree with the use of "bulk power system" in the applicability. The GVSDT has revised this to use the term "Bulk Electric System" instead. Concerns were raised regarding the verification schedule for entities that own five or fewer units. The GVSDT removed Sections 5.1.1 and 5.2.1. Entities that own one unit will be required to verify their unit within two years. Entities that own two units will be required to verify one unit within two years and both units within three years. The GVSDT received some comments regarding the language in Attachment 1. As a result the GVSDT restructured item 2 of Attachment 1:

2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification (see Note 3 if the automatic voltage regulator is not available). Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. A Reactive capability test must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data:

2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.

2.1.1 Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.

2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:

2.2.1 At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.

2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.

2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.

2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.

2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

Some commenters had questions regarding Section 5.3 regarding wind farms. The GVSDT acknowledges that this statement was placed in the standard as an explanation and is not appropriate to be included as section 5.3 This information was expanded and included as a footnote rather than section 5.3:

[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Organization	Yes or No	Question 4 Comment
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of ‘bulk power system’ to ‘Bulk Electric System’ would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Essential Power, LLC	Affirmative	1. There is a typo in R2- the requirement is for 'Reactive' Power verification, rather

Organization	Yes or No	Question 4 Comment
		than 'Real' Power verification.
Response: The GVSDT thanks you for your comment. The SDT agrees and has corrected the mistake.		
Pacific Gas and Electric Company	Affirmative	See comments from WECC
Response: The GVSDT thanks you for your comment. See response to WECC comments.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Alliant Energy Corp. Services, Inc.	Negative	Alliant Energy believes the use of the term "bulk power system" in the context of this standard is incorrect and the term "Bulk Electric System" should be used instead.
Response: The GVSDT thanks you for your comment. The SDT agrees and has made the change.		
Beaches Energy Services	Negative	BPS vs. BES The primary issue is the use of the Statement of Compliance Registry Criteria (SCRC) language in the standard which refers to bulk power system (BPS) instead of BES. This results in ambiguity because the BES is not the same as the BPS because BPS includes control systems whereas the BES does not. And because BES and BPS are not the same, compliance staff has also used the mismatch to overreach (e.g., CAN-0016 on CIP-001 that Mr. Caulay remanded is a prime example of this overreach). FMPA has made comments to the BES definition phase 2 SAR to ask the SDT to clarify the relationship between BES and BPS and has suggested in those comments that: BPS = BES + (protection and control systems covered by the standards) To parallel the Section 215 definition of BPS at (a)(1) "The term `bulk-

Organization	Yes or No	Question 4 Comment
		power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network ..." We have not heard from the BES definition team yet whether they will address this issue. A fix is to lean more on the term "Facility", which by definition is part of the BES, and simplify the language of the applicability section. A benefit of doing so is that, if the BES definition changes (e.g., phase 2 of the BES definition project), then no changes would be needed to the Applicability to the standards because the term "Facilities" will already incorporate any change to the BES since the definition of a Facility is "... a single Bulk Electric System Element". MOD-025 Applicable Facilities could be simply those that are not Black-Start., simplifying the language considerably
Response: The GVSDT thanks you for your comment. The SDT has changed references to the "bulk power system" to refer to the BES. Applicability to Black-Start units is no longer part of this standard as it is included in EOP-005-1.		
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Response: The GVSDT thanks you for your comment. Please see the response to the ACES Power Marketing comments.		
Central Electric Power Cooperative	Negative	see Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see the response to the AECI comments.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility."
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		

Organization	Yes or No	Question 4 Comment
Consolidated Edison Co. of New York	Negative	See Individual Company and NPCC Group comments
Response: The GVSDT thanks you for your comment. See response to Individual Company and NPCC Group comments.		
CPS Energy	Negative	1) The standard does not clearly define the term “applicable facility”. Are variable generating units such as wind, solar, and hydro included or excluded as applicable facility. 2) Disagree with the new “A Introduction 5.3 Wind Farm Verification” statement. This is a technology specific exception without justification.
Response: The GVSDT thanks you for your comment. **1) Any Facility that meets the requirements of Section 4 of the standard are included as applicable facilities regardless of their type. In general, variable generation sources are included in the applicability of this standard, provided they meet the specifications in Section 4 of the standard.** **2) The GVSDT has removed section 5.3 and included it as a footnote to Section 5.1 and 5.2 which reads:** **“Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.”**		
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
Flathead Electric Cooperative	Negative	do not like the reference to bulk power system as opposed to bulk electric system, don't like the mixing of terms in the same standard/document
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the “bulk power system” to refer to the BES.		

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Pool	Negative	See FMPA comments
Response: The GVSDT thanks you for your comment. Please see responses to FMPA comments.		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see responses to MRO NSRF and ACES Power Marketing Comments.		
JEA	Negative	MOD025-2: 1) R2 should be changed from "Real Power" to "Reactive Power" since R1 deals with Real power while R2 deals with Reactive Power. 2) Staged testing should not be required but instead rely on providing a longer window for an excursion to occur. It makes little sense to say that four 15 MVA units at a facility (for a total of 60 MVA) will not need to be verified and yet a single 20 MVA unit will need to be verified. Suggest making a consistent rule of 75 MVA for both single and aggregate units which is alignment with current thinking on phase 2 of the definition of the BES. 3) The allowance for when a combined facility is less than 90% should be further refined to say that the net value must be greater than 75MVA to require testing - i.e. if a facility is only at 40% of 100MVA (only 4 of 10 - 10MVA units available) capacity then testing should not be required.
Response: The GVSDT thanks you for your comment. 1) The GVSDT agrees and has made this revision. 2) This comment relates to MOD-026 and MOD-027. MOD-025 requires a staged test at a steady-state output for the Real and Reactive Power output verifications. The GVSDT has incorporated NERC generator registry criteria as the applicability for this standard. 3) The 90% allowance only applies to the verification of the Reactive Power capability of the variable resources. This means that 90% of the units at a site have to be on-line and does not represent the actual power output of the site.		

Organization	Yes or No	Question 4 Comment
Lakeland Electric	Negative	See FMPA comments.
Response: The GVSDT thanks you for your comment. Please see response to FMPA comments.		
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Response: The GVSDT thanks you for your comment. Please see response to MRO NERC Standards Review Forum for LES' concerns.		
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
MidAmerican Energy Co.	Negative	The inclusion of "bulk power system" in these standards is inappropriate. The term bulk power system is broad, vague, and undefined. All entities, including regulators and regulated entities must clearly understand the scope of compliance. See the NSRF comments for further discussion.
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES.		
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		

Organization	Yes or No	Question 4 Comment
Modesto Irrigation District	Negative	We strongly support generator testing and verification. However, the use of the undefined term "bulk power system" in the standard will lead to needless confusion. Also, we believe the intent of the coordination and testing standards is to recognize the importance to the Bulk Electric System (BES) of all interconnected generators with a capacity greater than 20 MVA. Hence, perhaps interconnected generators of this size should be included in the BES.
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES. Generators greater than 20 MVA are included in the applicability.		
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
Response: The GVSDT thanks you for your comment. Please see the response to NSRS comments.		
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Response: The GVSDT thanks you for your comment. Please see response to comments submitted by NPCC Reliability Standards Committee.		
New York Power Authority	Negative	See NPCC submitted comments
Response: The GVSDT thanks you for your comment. Please see response to NPCC submitted comments.		
North Carolina Electric	Negative	Please see the formal comments submitted by ACES Power Marketing.

Organization	Yes or No	Question 4 Comment
Membership Corp.		
Response: The GVSDT thanks you for your comment. Please see response to formal comments submitted by ACES Power Marketing.		
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same
Response: The GVSDT thanks you for your comment. The SDT agrees and has changed references to the "bulk power system" to refer to the BES.		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard MOD-025-2. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. The testing required in the proposed standard is onerous and quite expensive for small GO. To collect the required data would take an outside contractor to be hired. We do not understand why this data must be collected every five years for data that for a hydro does not change unless a generator winding fault or event occurs. Who uses this data? Suggest the following changes to Attachment 1 to the standard: Verification of data every 15 years or within 12 months if a change occurs. Only require MW & MVAR verification using operation data once every five years Paragraph 2.3 Conduct the maximum Real Power and over-excited Reactive Power required in 2.1 for a minimum of 5 minutes. Conducting these tests for one

Organization	Yes or No	Question 4 Comment
		continuous hour is like driving your car as fast as it can go in first gear - Nothing good comes out of it. I am concern about the overvoltage situation to our equipment. On line voltage runs high; being a smaller plant, we have ever little control over what the line voltage is. Running these tests for an hour would damage our equipment. Paragraph 2.6 If transformer loss data is not available then collect Generator Step-Up (GSU) transformer losses......... Transformer losses change very little through their life. I do not see the reasoning behind collecting this data every five years - seems like overkill to me. Paragraph 3.2 Do not understand the requirement about voltage schedule during a test. Running the reactive testing the voltage is going to run where the loading is going to take it. Please provide a further explanation MOD-025 Attachment 2 Our hydro plant does not track other plant loads - they are minor in nature and unlike thermo or nuclear plants are not a high percentage of generation. I would prefer that the standard requires for hydro plants that the nameplate real and reactive power limits be tested every five years. The other data is not necessary to obtain.
Response: The GVSDT thanks you for your comment. The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification. It is expected that the TP will use the data. Operation of units beyond their design capability is neither required nor expected. Attachment 1, Section 2.6 has been reworded for clarity. Transformer losses are meant to be measured or calculated so that new MW's and MVAR's can be determined. The voltage schedule for the test (and the voltage window) would be needed to be sure transmission voltage limits are not exceeded for the tests (coordination with the TO is expected). Your statement concerning a preference for testing hydro plants every five years does not seem to be consistent with an earlier statement suggesting verification every 15 years. The GVSDT, however, agrees that testing every five years is the correct verification frequency.		
Seattle City Light	Negative	Attachment 1 “Verification specifications for applicable Facilities:” section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors.
Response: The GVSDT thanks you for your comment. In Attachment 1, Section 2.3, maximum power for variable energy units would be the highest power level (not emergency overload) that the unit can sustain for one hour. The GVSDT suggests		

Organization	Yes or No	Question 4 Comment
scheduling the tests requiring a one hour stabilization period when conditions are adequate. Alternately, you can test variable energy units at the level that can be sustained for one hour per Attachment 1, Section 2.1. Attachment 1, Section 2.1 also states that the output should remain as steady as possible during the verification period.		
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
SERC Reliability Corporation	Negative	Please see comments of SERC Dynamics Review Subcommittee regarding reactive capability planning.
Response: The GVSDT thanks you for your comment. Please see response to SERC Dynamics Review Subcommittee comments.		
Southwest Transmission Cooperative, Inc.	Negative	The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on subtransmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: "The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric

Organization	Yes or No	Question 4 Comment
		system." Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies that standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. We also find section 5.3 regarding wind farm verification confusing. What is its purpose?
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) Section 5.3 in the "Effective Date" was for clarification to let people know that a wind farm site, if it meets the applicable facility criteria, is a single site. This text has been moved to a footnote to the Applicability Section, 4.2.3.**		
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see response to ACES Power Marketing comments.		
Tucson Electric Power Co.	Negative	Measure M1 references corrections for ambient conditions, while there is no reference to ambient conditions in Requirement R1. However, Requirement R1 requires verification in accordance with Attachment 1 and corrections for ambient conditions is identified in Attachment 1. This should be referenced or made clearer.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was		

Organization	Yes or No	Question 4 Comment
recorded/selected whichever is later."		
Xcel Energy, Inc.	Negative	Measure M1 creates a requirement to perform an activity that is not mentioned in the Requirements.
	Negative	Measure M1 creates a requirement "and a correction for ambient conditions, if requested, within 90 days to its Transmission Planner" not found within the Requirements section of the Standard.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."		
Central Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
Response: The GVSDT thanks you for your comment. Please see response to AECI comments.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement will be a cause of confusion. Please fix it now before the standard is approved.
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		
Luminant Generation Company LLC	Negative	Based on a comparison of R2 and corresponding VSL. It is unclear how the time frames are to be aligned. Comments on the standard provided in the on-line

Organization	Yes or No	Question 4 Comment
		comment form.
Response: The GVSDT thanks you for your comment. R2 requires that the verified data be submitted within 90 calendar days. The VSLs are based on a violation of that timing requirement.		
New York Power Authority	Negative	See NPCC Submitted Comments
Response: The GVSDT thanks you for your comment. Please see response to NPCC comments.		
Tucson Electric Power Co.	Negative	The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. Suggest using "less than or equal to" and "more than" as more clear identifiers. Same for R3.
Response: The GVSDT thanks you for your comment. The VSL's have been modified for clarity as you suggest.		
Northeast Power Coordinating Council		1)This testing will be difficult to stage due to the four point reactive power testing. The power system may have to be reconfigured in many cases to allow for the changes in generator reactive power output, and the testing may not be able to be carried out when planned. System disturbances can occur that will disrupt the testing. 2)For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are "on-line". For reactive testing, this would be better stated as 90% of the plant's available capability considering that some wind turbines may be able to produce/absorb reactive power with no real power production. Does "on-line" just imply that the wind turbine breaker is closed and no requirement for real power production? 3)In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power

Organization	Yes or No	Question 4 Comment
		connected at the high-side of the generator step-up transformer (point D), and Aux or Station Service Real Power connected at other points of interconnection (point E). Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)? 4)The data requested in this Standard will verify a generator's capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these Standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies (and not include synchronous condensers). Therefore, the Purpose Statement be edited to read: "To assure accurate information on generator gross and net Real and Reactive Power capability Reactive Power capability is available for planning models used to assess BES reliability." 5) The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime, unless the generator has been rewound, cooling systems modified, installation of a new exciter, etc. 6) Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? A GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. 7) 2. Comments on Attachments 1 and 2: The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. 8)o Notes 1 - 4 at the end of Attachment 1 should be removed from the Standard

Organization	Yes or No	Question 4 Comment
		and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. 9)o Section 4.2.1 (and elsewhere): the term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability Sections is confusing.

Response: The GVSDT thanks you for your comment.

1) **The GVSDT acknowledges that other reactive resources may need coordination in order to complete a staged test. The standard encourages coordination to achieve better test results but does not require reconfiguration of the power system in order to facilitate a staged test.**
2) **The intent is to have 90% of the individual turbines or inverters on line with the breakers closed. There is no requirement for real power production from variable resources during reactive power testing.**
3) **Data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability.**
4) **The GVSDT received overwhelming stakeholder support favoring the inclusion of synchronous condensers in the standard during the previous posting. The GVSDT believes that the purpose statement is adequate for the standard as written.**
5) **Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities.**
6) **The GVSDT has removed 5.1.1 and 5.2.1 so that entities with only one unit will have two years to complete a test. Entities with two units would have three years and so on.**
7) **Data is required for all points if it is available. In accordance with the purpose statement of the standard, the data required is net real and reactive capability. Point A is the gross generator output. The verification of net output is required, so the other values are needed to derive the net. The ratings are just that, ratings not necessarily what can actually be output. As discussed in item 3, data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability.**
8) **The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.**

Organization	Yes or No	Question 4 Comment
9) The GVSDT agrees and has made the revision from bulk power system to Bulk Electric System.		
SERC Generation Subcommittee		1) Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions (if requested), but this is not included in R1, Attachment 1 or Attachment 2. 2) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. 3) Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. 4) To accomplish the stated goal of Steady State Model Validation, there needs to be clarity in the definitions for model terms. We have developed a draft set of definitions that is available to the SDT. 5) Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which provided a process where an engineering review (with associated operating data) should be performed first with testing to be done on a limited basis, if needed, to capture data not covered by an operational review. The SDT could leverage this guide to better understand the approach, which was agreed to by the region's planning and generator operators. This approach should be adopted as an additional method to verification. 6) Testing may be desirable to identify issues, such as incorrect AVR limiter settings, but there are other methods that also would accomplish those goals. If the goal is operational testing to uncover these types of issues, that should be clarified in the

Organization	Yes or No	Question 4 Comment
		purpose of the standard as opposed to the stated goal of model validation. 7) Attachment 1, Verification specifications for applicable Facilities, Note 1: We recommend revising the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” 8) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 9) The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. 10) Attachment 2, Summary of Verification - What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. o Applicability Section - change “bulk power system” to “BES”. 11) Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. 12) Testing a unit to the limits of its protective function (such as overvoltage) creates

Organization	Yes or No	Question 4 Comment
		the possibility for an unplanned unit trip, particularly problematic on nuclear units.

Response: The GVSDT thanks you for your comment.

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

3) The use of operational data is optional and not required. The intent of the suggested criteria was meant to be as flexible as possible while requiring a reasonable staged test to insure adequate effectiveness of the period/data chosen to use for operational tests.

4) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported.

5) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone.

6) The goal of MOD-025 is to verify real and reactive power output. The types of issues that you reference may impact the output.

7) Note 1 has been modified to incorporate the suggested wording.

8) Periodic verification is necessary to discovering the equipment limitations that impact the unit MW or MVAR capabilities.

9) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported. The Generator Owner provides the verification results to the Transmission Planner for inclusion in the development of their models.

10) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage

Organization	Yes or No	Question 4 Comment
appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2. **11) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.** **12) This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions.**		
SERC Dynamic Review Subcommittee (DRS)	Yes	1) VAR-002-1.1b Requirement R1 states "The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator." However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. The DRS recommends that MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the DRS recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard.

Organization	Yes or No	Question 4 Comment
		2) On Attachment 2 Comment Section for Point A, add note that "individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) 3) On Attachment 1, item 2.6, add sentence stating that "GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary." If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. 4) On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. 5) The DRS recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of "sister unit" concept. This will facilitate more consistent unit verifications. 6) The DRS agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. The DRS recommends that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar

Organization	Yes or No	Question 4 Comment
		changes which impact the reactive testing results. 7) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.

Response: The GVSDT thanks you for your comment.

1) The GVSDT does not intend for a unit to change voltage regulator control modes in order to complete testing but simply makes it clear that testing is still to be done if the automatic voltage regulator is either not used or not available. It would be preferred that the test be rescheduled for a time when the automatic voltage regulator is operational if possible. Coordination of limiters with protection and generating unit capabilities is not the intent of this standard. Please reference PRC-019-1. MOD-025-2 also does not require operation outside the capabilities of the unit.

2) The GVSDT agrees that this change adds clarity, and will modify Attachment 2 as you suggest.

3) Your suggested revision has been adopted for clarity.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

5) Standards MOD-025-2 and PRC-019-1 are closely related and have been matched as closely as possible for consistency. These two standards, however, are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and therefore, would have a longer period between re-verifications.

6) After the first staged test, operational testing is allowed and further staged testing may not be required. Either operational or staged testing is intended to identify problems that cannot be identified by plant configuration change, major equipment changes, power system topology changes, or similar changes which impact the reactive testing results.

7) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

Organization	Yes or No	Question 4 Comment
Imperial Irrigation District (IID)		2.3 and 2.4 need clarification whether the real and reactive tests are run separately or concurrently and if that is 1 hour each or 1 hour total.
Response: The GVSDT thanks you for your comment. In Attachment 1, 2.3, the one hour stabilization period is required for MW testing and MVAR testing overexcited at full load. From Attachment 1, "It is intended that Real Power testing be performed at the same time as full Load Reactive Power testing, however separate testing is allowed for this standard." If the tests are done at the same time a one hour stabilization period would be adequate (not one hour for each test). It is expected that the stabilization period done in 2.3 would most likely be a "worst case" scenario and therefore, would not need to be completed for the tests in Attachment 1, 2.4. The data for the tests in Attachment 1, 2.4 can therefore, be recorded as soon as the limit is reached.		
Santee Cooper		1) Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. 2) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities. 3) Attachment 1 item 2, referencing the use of operational data, is confusing and ineffective. While we strongly support the use of operational data, the criterion listed is not functional and we recommend deleting it. The proper use of operational data should be left up to the entity to determine. 4) Testing by itself cannot accomplish the goals of validating models. SERC developed a generator model validation guide in ~ 2004 (the precursor to the current SERC regional criteria), which laid out a process where an engineering review and operating data should be performed 1st and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the regions planning and generator operators. This approach should be adopted as an

Organization	Yes or No	Question 4 Comment
		additional method to verification. 5) Attachment 1, Periodicity for conducting a new verification: 2) We do not see significant value in a 5-year re-verification cycle. We believe periodic confirmation of previously verified MW and MVAR capabilities does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 6) The assignment of responsibility for model validation on the generator owner is less than desirable for several reasons. The GO does not maintain modeling expertise needed to understand the bases for model data. The GO/GOP would typically not be able to choose optimal system conditions needed to fully validate data and be required to write test procedures to cover this operation. The System Operator Engineering staff would have access to the latest model data. They already have the authority to direct the operation of generation units as needed to prove the data in the operations models. The planning models could then be pulled from the operational models and thus this approach would serve to validate both. 7) Attachment 2, Summary of Verification - What is the purpose of the fifth bullet? (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) This appears to imply analysis is needed/effective to adjust to rated generator voltage. 8) Applicability Section - change “bulk power system” to “BES”. 9) Credit should be given to real/reactive verification done in the recent past under regional oversight. Also, some applicability to similar or “sister” units should be allowed. 10) Testing a unit to the limits of its’ protective function (such as overvoltage) creates the possibility for an unplanned unit trip, particularly problematic on nuclear units.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 4 Comment

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

3) The use of operational data is optional and not required. The intent of the suggested criteria was meant to be as flexible as possible while requiring a reasonable staged test to insure adequate effectiveness of the period/data chosen to use for operational tests.

4) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone.

5) Your suggestion about the period of the re-verification cycle has merit and should be considered for a future revision to this standard if proven over time.

6) The goal of MOD-025 is to verify real and reactive power output. The GVSDT believes that the data points shown in Attachment 2 are sufficiently defined to allow for accurate data to be reported. The Generator Owner provides the verification results to the Transmission Planner for inclusion in the development of their models.

7) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.

8) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

9) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units.

Organization	Yes or No	Question 4 Comment
10) This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions.		
Dominion- NERC Compliance Policy		1)Dominion points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2. 2)Additionally, on Attachment 1 at 2.2, "Applicable Facilities" should be changed to "applicable Facilities" to be consistent with usage elsewhere in the standard. 3) VSL's for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33.* VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from "more than 12 calendar months but less than or equal to 13 calendar months" to "greater than 15 calendar months." 4) Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word "reactive" be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." 5) Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. 6) Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..."

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. **1) We have revised the Applicability section by removing the phrase "bulk power system" and replacing it with the defined term "Bulk Electric System"** **2) We concur and have made the change.** **3) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.** **4) Attachment 1, 2 has been modified for clarity and now reads in part: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data."** **5) Attachment 1, 3.7 has been modified for clarity. It now reads: "The GSU Transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.** **6) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads in part: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires….."**		
FirstEnergy		FirstEnergy has the following comments related to Attachments 1 and 2: 1. Att. 1 Sec. 2 - We suggest replacing the phrase "that demonstrated at least 50 percent of the capability of the associated D-curve" with "that demonstrated the maximum capability of the associated D-curve". 2. In addition, we suggest language as follows: "The reason(s) for any verified Reactive Power capabilities that, due to plant equipment, are more constraining than the appropriate generator Reactive Power capability curve (D-curve) shall be documented. (For example, exciter or generator field current limitations, generator terminal voltage, auxiliary or safety-related bus voltage limitations, volts per Hz alarms, excessive generator vibration, generator temperature limits, hydrogen

Organization	Yes or No	Question 4 Comment
		coolers restrictions, shorted rotor turns, safety, other protection, etc.) 3. Att. 1 Sec. 3.4 - Although we understand the drafting team does not want to be prescriptive and dictate an ambient temperature methodology, we believe the requirement is too broad and up for much interpretation across entities and regional auditors. There should be a more standardized method of determining the ambient adjustment for consistency, for example something similar to RFC standard MOD-024-RFC-01 Requirement R4.3.3. 4. We suggest adding the following or similar wording in the standard when a verification cannot be completed due to operational issues and include the allowance of engineering analysis to complete the verification: “1.2.3 If a verification test has been started and cannot be completed due to a transmission system limit or condition, this transmission system limit or condition shall be documented, and engineering analysis taking into account known limitations shall be used to determine the verified capabilities.”
Response: The GVSDT thanks you for your comment. **1) The phrase “that demonstrated at least 50 percent of the capability of the associated D-curve” was added recognizing that some units may always be limited by system conditions from reaching their D-curve. Operational testing would still be allowed on a re-test if it were within 90% of a previous test where a reasonable capability (50%) had been demonstrated. In our last posting we had stated exactly as you suggested but, in response to comments changed it to a more reasonable qualification.** **2) Reasons for not reaching the D-Curve are to be documented, see the “Remarks” section of Attachment 2.** **3) The GVSDT feels that the differences between units are too great to attempt an ambient temperature methodology to fit all and that it should be left up the owner to determine the best methodology for its units.** **4) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.**		
SERC Planning Standards		1) Change references to “bulk power system” in the Applicability section to “Bulk

Organization	Yes or No	Question 4 Comment
Subcommittee		Electric System.” 2) VSL’s for R1: The Moderate VSL should start at missing 34 percent of the data instead of 33. 3) VLS's for R1, R2, and R3: The last Severe VSL listed should be changed from “more than 12 calendar months but less than or equal to 13 calendar months” to “greater than 15 calendar months.” 4) Attachment 1, "Verification specifications for applicable Facilities" section, item 2: The words "is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve" seem to apply to both Real and Reactive power verifications. Should the D-curve reference only apply to Reactive? We recommend that the word “reactive” be inserted into the sentence as indicated below: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the reactive capability shown on the associated D-curve." 5) Attachment 1, item 3.7: For clarity add the words "(real and reactive)" after losses. 6) Attachment 1, item 3.4: For better readability add the word "that" after "period" so that it reads "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires..."

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to “bulk power system” with the NERC defined term BES.

2) and 3) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.

4) Attachment 1, 2 has been modified for clarity and now reads in part: “Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a)

Organization	Yes or No	Question 4 Comment
that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." **5) Attachment 1, 3.7 has been modified for clarity. It now reads: "The GSU Transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.** **6) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires…"**		
PPL		Comments: 1) A reference to power factor is needed in para. 2 of the Att.1 verification specification statement, "at least 50 percent of the capability shown on the associated D-curve." Is this criterion intended to apply at 1.0 PF? 2) Para. 2.1 of the verification specification in Att.1 is unclear in citing, "normal (not emergency) expected maximum Real Power." Normal operating level is typically not the maximum of which a unit is capable. Suggest this test-to generation be changed to, "normal full-load Real Power," defined as the output at which the unit usually runs for the ambient conditions existing at the time of the verification. 3) Add, "for the conditions existing at the time of the verification," at the end of the first sentence of para. 2.2 in the verification specification in Att.1. 4) Change "collect" to "correct for" in verification specification para. 2.6 in Att.1. 5) The statement, "The ambient conditions, if applicable, at the end of the verification period the Generator Owner requires to perform corrections to Real Power for different ambient conditions," in para. 3.4 of the verification specification of Att.1 is not clear. Possibly an "if" was intended before "the Generator Owner." A reference condition is also needed, or instructions for identifying the correct-to criteria, if the as-tested normal real power is to be adjusted for ambient conditions.

Organization	Yes or No	Question 4 Comment
		Such correction often does not apply for the purposes of this standard, however. A fossil unit with an emergency max capability of 750 MW on a 90 F day can achieve higher output at 60 F, for example, but the normal output may be 725 MW regardless of ambient conditions (see comments above). 6) Add, “Transformer Real and Reactive Power losses will also be estimates or calculations,” to para. 4.1 in the verification specification of Att.1, as well as the statement, “Only output data are required when using a computer program to calculate losses or loads.” 7) Note 2 the verification specification of Att.1 states, “While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification.” It is unclear who supposed to undertake such analyses and how they could be performed. Suggest this note be clarified or dropped. 8) The purpose of having a MOD-025 standard is undercut by the statement in Note 4 of the verification specification in Att.1 that “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” It is unclear why these tests should be performed if the results aren’t used? Could MOD-025-2 be withdrawn in light of FERC’s March 15, 2012 FFT Order to propose specific standards or requirements that should either be revised or removed due to having little effect on reliability or because of compliance burdens. 9) Add “Reactive Power” between “unit’s” and “capabilities” in Note 4 of the verification specification in Att.1. 10) It appears that the aux and net values requested in Att.2 are intended to be low-side readings, in which case they should be so-identified. 11) Delete from Att.2 the statement, “The recorded Mvar values were adjusted to rated generator voltage, where applicable.” Such adjustments may have unsuitably

Organization	Yes or No	Question 4 Comment
		high uncertainty.

Response: The GVSDT thanks you for your comment.

1) Attachment 1, 2 has been modified for clarity and now reads in part: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below. For a Reactive Capability test, it must demonstrate at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive Power capability shown on the associated D-curve." It does not refer to a 1.0 PF test since this test is not required in this standard.

2) "Normal (not emergency) expected maximum Real Power" means the expected full load that can be counted on without configuring the unit in an unusual manner to gain additional MW's.

3) The GVSDT does not feel that the additional phrase adds clarity to Attachment 1, 2.2 as the generator owner selects the output at which the units are normally expected to operate.

4) Attachment 1, 2.6 has been modified for clarity and now reads: "Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU Transformer."

5) Attachment 1, 3.4 has been modified for clarity as you suggested. It now reads: "The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires…". If a unit's capability does not change with ambient conditions, then that should be reported if requested by the Transmission Planner. The GVSDT has also added item 4.2 to Attachment 1: "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

6) The GVSDT concurs and has made the revisions suggested.

7) It is anticipated that Engineering Analysis would be performed by someone familiar with power system modeling. Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.

8) Your comment applies to Note 1. The GVSDT has revised Note 1 to provide clarity on the intent of the statement. Note 1 now

Organization	Yes or No	Question 4 Comment
reads: "Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2." **9) Attachment 1, Note 4 has been modified for clarity. Note 4 now reads in part: "The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities."** **10) The auxiliary and station services values would be as measured at the 'high' side of those transformers. The net value is intended to be the net out of the generating unit or site as applicable. The GVSDT believes that the diagram is clear on these points.** **11) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
ACES Power Standards Collaborators		1)We disagree with testing a unit with capability to operate in synchronous condenser mode in that mode. Most likely the unit would only operate in this mode in an emergency situation. Thus, it does not make sense to operate a unit in an emergency mode for a test. 2)We do not agree with adding a last verification data column in Attachment. This only causes confusion. Will it be clear to auditors that the last verification data column is to remain blank for the initial verification or will we end up with a similar situation to the Protection System Maintenance and Testing standard where auditors required evidence from before the enforcement date of standards? Ultimately, the NERC CEO had to overrule this situation. Furthermore, it creates additional work to transfer data from a previous verification test to the current test when the past sheet could simply be retained. Finally, it causes confusion with the data retention section because the data behind Attachment 2 must be retained. Is this intended to

Organization	Yes or No	Question 4 Comment
		be only the latest verification or does it include the last verification? 3)Item 2 of the verification specifications for applicable Facilities in Attachment 1 conflicts with Parts 1.2, 2.2, and 3.2 of the Requirements R1, R2 and R3. The attachment states that historical data going back two years can be used. However, the requirement parts state that the data must be submitted with 90 days to the Transmission Planner. That would appear to limit the historical data to 90 days. The attachment never makes it clear if you can switch between operational data and staged verification from one test to another. The confusion is caused by the separate listing of periodicities in items 1 and 2 under the “Periodicity for conducting a new verification” section. A close reading of the two items shows they are identical but listed separately to make the statement about listing the “earliest date of those dates” for the operational data. We suggest combining item 1 and 2 together will help eliminate this confusion. 4)We disagree with the need to conduct another staged test rather than using operational data as specified in Attachment I subsection 2 in the “Verification specifications for applicable Facilities:” section. If operational data can be used to satisfactorily verify the unit’s real and reactive power output, it should always be allowed to avoid the need for a staged test.

Response: The GVSDT thanks you for your comment.

1) The standard applies to both stand alone synchronous condensers ad hydro units that can be used in condensing modes. The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator.

2) The intent of the drafting team in adding this information is to show compliance for the use of operational data. The drafting team cannot predict what auditors might do, but we will add a note that states this area would be blank for the first verification.

3) The GVSDT does not see a conflict because R1.2, R2.2 and R3.2 state that you have 90 calendar days from the date the data is selected, not the date the data is recorded. Requirement’s R 1.2, R2.2 and R3.2 all state: “Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either

Organization	Yes or No	Question 4 Comment
the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data." **4) A staged test is always required for the first test as a part of this standard. The sentence "If the previously staged test was unduly restricted by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data" was added to disallow operational data being qualified based on a staged test that was not indicative of what can be expected from the unit due to unusual operating conditions at the time of the last staged test. Therefore, a successful staged test must be completed before operational data can be used on subsequent tests.**		
Puget Sound Energy		Very rarely will you get to the capability curve when testing real and reactive power. There is almost always a protective limit or you exceed 105% voltage. NERC does not specify what will prevent you from reaching maximum VAR output, so we assume that is up to the testing engineer.
Response: The GVSDT thanks you for your comment. The GVSDT agrees that it is up to the testing engineer to recognize when a limit has been reached. Coordinating with other nearby resources may allow you to reach the capability curve within the voltage limits of the unit. Attachment 2 requires documentation for the specific limit reached, see the section on "Remarks".		
Western Electricity Coordinating Council		1)Measure M1 specifically references corrections for ambient conditions as part of the evidence required, but Requirement R1 does not specifically call out corrections for ambient conditions. The only reference to corrections for ambient conditions is in Attachment 1. For consistency it seems the Requirement detail and the Measure detail should be the same. 2)The Lower and Moderate VSLs for R1 both include missing 33 percent of the data in the condition identified after the first OR in the VSL. If an entity was missing exactly 33 percent of the required data, it would not be possible to identify an appropriate VSL. WECC Staff recommends the use of the identifiers "less than or equal to" and "more than" to resolve the issue, and recommends that clarification be extended to the rest of this section of the VSLs for R1.The section of the VSLs for R3 that use percentages as the identifier should use "more than" and "less than or equal to" qualifiers.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. **1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **2) The GVSDT has revised the VSLs to correct the problems that you noted.**		
Tennessee Valley Authority - GO/GOP		Testing a unit to the limits of its' protective function (such as overvoltage) creates the possibility for an unplanned unit trip. The SERC Regional Criteria for MOD-024 and MOD-025 allows an engineering assessment in conjunction with operational data review as a valid verification method. MOD-025-2 should include an engineering assessment as a valid method of verification.
Response: The GVSDT thanks you for your comment. This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions. Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.		
Arizona Public Service Company		Need for real power verification and reliability benefits are not clear. Similarly need for and reliability benefits of all the detailed calculations are not clear. The drafting team should poll the industry as to the reliability benefits and determine out who will use the information and what is the benefit of such detailed reporting.
Response: The GVSDT thanks you for your comment. Accurate, verified real and reactive Power output helps to ensure reliability in more accurate planning models as stated in the purpose statement of the standard: **"To ensure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability."**		

Organization	Yes or No	Question 4 Comment
Southern Company		1) Applicability, Section 4: Applicability for MOD-025 and PRC-019 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to inidividual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to focus on standard requirements that have significant impacts on system reliability, and including smaller units (without demonstrating their criticality to the system) seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where relability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. 2) Attachment 1, Periodicity for conducting a new verification: We do not see significant value in a 5-year re-verification cycle. We believe a periodic confirmation that the previously verified MW and MVAR capabilities are still valid does have value. Re-verification should only be necessary when there is a long term configuration change, a major equipment modification, or equipment problems that impact the unit MW or MVAR capabilities. 3) Attachment 1, Verification specifications for applicable Facilities, Item 2: Delete the requirements for mandatory “staged testing”. Allow staged testing as an alternative. There is no industry consensus that staged testing is superior or achieves better reliability results for modeling purposes than the use of operational data coupled with a proper engineering study. A staged test performed every 5 years in our experience is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending, and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit. Staged testing alone typically does not prove a unit’s reactive capability, because the unit’s true reactive limit cannot be reached due to transmission voltage and reliability constraints during the test period. We believe staged testing alone cannot accomplish the reliability

Organization	Yes or No	Question 4 Comment
		purpose of this standard. While staged testing can identify problems such as incorrect AVR limiter/protection settings or non-optimum transformer tap settings, these problems can be identified and corrected without staged on-line testing. 4) Attachment 1, Verification specifications for applicable Facilities, Item 3.4: This increases the complexity and reporting requirements for compliance. In practice, we believe the margins of error in transmission models do not require this level of detail and accuracy for periodic verification of unit MW capability. For the purposes of this standard, we believe recording of the MW for typical normal summer or winter conditions is sufficient. If a unit's MW capability is in question, TOP-002-2b R13 already has provisions for performing a more detailed verification, including ambient and water temperature conditions, at the request of the BA or TOP. 5) Attachment 1, Verification specifications for applicable Facilities, Note 1: Revise the last sentence to state, “The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit’s reactive capability for extreme system conditions. See Note 2.” 6) Please add page numbers to every page of the standard. 7) Attachment 2, Summary of Verification - What is the purpose for the fifth bullet? MVARs are a function of both the generator voltage and the system voltage. Thus, how to adjust the recorded Mvar values to rated generator voltage is not clear, is subject to dispute, and implies that engineering analysis is required to determine this result. 8) Attachment 2 Remarks - It is unlikely that the generator capability curve will be reached either during a lagging VAR test or during collection of operational data when a GSU tap has been set to support the normal system voltage ranges. The generator should be able to support the normal system voltage range without producing a large amount of Vars or amps so the Vars (or thermal capabilities) are held in reserve for extreme low voltage conditions. The transmission bus voltage will likely be the limiting factor during testing and normal operation. It is unlikely that

Organization	Yes or No	Question 4 Comment
		capability curve limit will be reached during either a leading VAR test or during collection of operating data. The limiting factor again is likely to be the transmission bus voltage. Likely unit operational limits which will prevent demonstration of the full range of the generator capability curve include the minimum excitation limit, the generator minimum voltage limit, or the station service minimum voltage limit. We recommend the Remarks statement be replaced with a list of possible limiting factors with checkboxes. If the transmission system voltage or a plant voltage limit is the limiting factor, the results of the test are inconclusive without performance of a supplemental engineering study. 9) The responsibility for requiring and coordinating any staged testing for the purposes of model validation already resides with the owners of the transmission models (i.e., the PC, TP, TOP and/or RC), not the GO or GOP. See TOP-002-2b R13. The TOP should initiate the request for the test and work with the GO/GOP to schedule the testing at a time when system conditions are optimal for testing that specific unit. The GO/GOP should only be responsible for supporting the TOP/RC during test scheduling, conducting the test, recording the necessary plant data, and reporting the test data and results, including any plant limitations encountered during the test. The GO/GOP can also perform any technical reviews and/or additional engineering analysis necessary to determine or confirm the expected MVAR limits to be used in the transmission models. This approach will better serve the reliability purpose of the standard. 10) Measure M1 doesn't match R1, or Attachment 1 or 2 regarding the submission of ambient condition correction information. (appears in M1, but not in the others) 11) An entity should be able to receive credit for real & reactive capability verification that has been done in the past 5-6 years which resulted from following existing regional requirements 1 12) For cases where operational data is used for verification, submittal of the results within 90 days of the date the data is recorded is inappropriate. Use of operational data involves the review and evaluation of unit data trends over an entire season as

Organization	Yes or No	Question 4 Comment
		a minimum. Two seasons are optimum based on our experience. R1.2 and R2.2 should be revised to state, "within 90 calendar days of completion of the verification."

Response: The GVSDT thanks you for your comment.

1) The GVSDT matched the implementation times of MOD-025-2 and PRC-019-1 which are closely related standards. These standards are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications.

2) Periodic verification is necessary to discovering the equipment limitations that impact the unit MW or MVAR capabilities.

3) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. The GVSDT does agree that staged testing is not a substitute for proper planning, proper implementation of limiter and protection settings, equipment monitoring, unit data trending and operational awareness and identification of plant equipment problems that could impact the MW or MVAR capabilities of a unit and these activities would be helpful in supplementing staged or operational testing.

4) The GVSDT does not feel it has been given the flexibility to eliminate corrections for ambient conditions due to the wording in FERC order 693, Paragraph 1310.

1310. In the NOPR, the Commission stated that the Reliability Standard could be improved by defining test conditions, e.g., ambient temperature, river water temperature, and methodologies for calculating de-rating factors for conditions such as higher ambient temperatures than the test temperature. With the test information and methodologies, the generator output that can be expected to be available at forecasted weather conditions can be determined.

Ambient temperature corrections are only required if it is requested by the Transmission Planner.

5) Note 1 has been modified to incorporate the suggested wording. Note 1 now reads "Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve)." However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap

Organization	Yes or No	Question 4 Comment
		settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2. 6) Future versions of the standard will have page numbers on every page. 7) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2. 8) Good estimates of actual VAR capacity are possible from testing with proper planning/generator coordination. The GVSDT agrees that there will be cases were the verification will not reach the maximum or rated values. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. A staged test or operational data verification at least demonstrates that the equipment can successfully reach that operating point. For the cases where testing does not provide a good estimate, engineering analysis can be used and is encouraged. The GVSDT does not feel a list is necessary nor will it add clarity and may even add further confusion to the document. The people performing the test are in the best position to determine and log the limiting condition. 9) MOD-025 deals with long-term planning models. The TOP-002-2b standard relates to operations planning and allows the BA or the TOP to request a test. It does not require a test on any periodic basis, but only upon request. 10) The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." 11) Credit may be taken for units that were tested under regional oversight if they fulfill the requirements of the standard. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units. 12) Requirement's R 1.2, R2.2 and R3.2 all clearly state: "Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data." This assumes that you

Organization	Yes or No	Question 4 Comment
have already reviewed and evaluated the unit and data trends before you select the data. Attachment 1, 2 states in part "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability".		
PacifiCorp		Yes. See below: PacifiCorp does not support the addition of the term "bulk power system" to Section 4.2.1 of the "Applicability" section (as well as to sections 4.2.2 and 4.2.3). The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the sentence would reads as follows: "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to Section 4.2.2 and 4.2.3.
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
Consolidated Edison Co. of NY, Inc.		Comments: 1. The data requested in this Standard will verify a generators capability curve. FAC-008, FAC-009, and IRO-010 Standards require TOs and GOs to develop facility ratings for real and reactive power (net and gross) and communicate those ratings. However, these standards may be inadequate in obtaining the generator capability curves. MOD-025 is a modeling Standard that will verify a generator capability curves for use in planning studies. Therefore, we recommend that the Purpose Statement be edited should read - o "To assure accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess BES reliability." 2) The effective dates require revision. This is a modeling Standard. Therefore, obtaining a generator capability curve is only necessary once in the unit lifetime,

Organization	Yes or No	Question 4 Comment
		unless the generator has been rewound, cooling systems modified, new exciter, etc. 3) Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 5 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 5 years after regulatory approval of the Standard. Is this the SDT's understanding?2. Comments on Attachments 1 and 2: 4) The only data point required for this Standard is Point A. All other points are identified in Facility Rating methodologies and can be removed from this Standard. Point D and E are not applicable to a GO or TO. These points are LSE data to be supplied to the TP for modeling purposes. 5) Notes 1 - 4 at the end of Attachment 1 should be removed from the Standard and put in a guidance document. These notes are not requirements, but suggestions and observations that could create compliance issues for GOs and TOs if the notes remain in the Standard. 6) Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing.

Response: The GVSDT thanks you for your comment.

1) **The GVSDT received overwhelming stakeholder support favoring the inclusion of synchronous condensers in the standard during the previous posting. The GVSDT believes that the purpose statement is adequate for the standard as written.**
2) **Periodic verification is necessary for discovering the equipment limitations that impact the unit MW or MVAR capabilities.**
3) **The GVSDT has removed 5.1.1 and 5.2.1 so that entities with only one unit will have two years to complete a test. Entities with two units would have three years and so on.**
4) **Data is required for all points if it is available. In accordance with the purpose statement of the standard, the data required is net real and reactive capability. Point A is the gross generator output. The verification of net output is required, so the other**

Organization	Yes or No	Question 4 Comment
values are needed to derive the net. The ratings are just that, ratings not necessarily what can actually be output. As discussed in item 3, data is not required for points D and E but should be included if they exist. In many cases, these additional loads will not exist. They are listed to ensure that they are not included in calculating point F which is the net unit capability. **5) The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.** **6) The GVSDT agrees and has made the revision from bulk power system to Bulk Electric System.**		
Luminant Energy Company LLC		Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour.2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as

Organization	Yes or No	Question 4 Comment
		soon as a limit is reached.2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section 3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2).On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope. 3)Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the simplified one-line diagram ..." Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E. 4)For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.

Response: The GVSDT thanks you for your comment.

1) The GVSDT agrees and has revised the standard as proposed. One exception was regarding the sentence about retesting within six months. Another commenter noted an error within that sentence.

2) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.

3) The GVSDT worded this to allow GOs to use their own form as long as it provides the required information. We believe that this flexibility is appropriate, and Luminant's suggested wording seems to require the Attachment 2 form only. We, therefore, decline to adopt this change.

4) The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not

Organization	Yes or No	Question 4 Comment
requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.		
South Carolina Electric and Gas		1) Sections 4.2.1, 4.2.2, 4.2.3 uses the term "bulk power system." should this be changed to "Bulk Electric System." 2) Attachment I, "Verification specifications for applicable Facilities", #2. The third sentence should be revised to read "... at least 50 percent of the REACTIVE capability ..." 3) Also, in the VSL section: R1, Moderate VSL should read "34 to 66 percent of the data." 4) R1, R2, R3 Severe VSL should read "greater than 15 calendar months."
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT agrees and has modified Attachment 1, Verification specifications for applicable Facilities for clarity. The sentence now reads in part "…at least 50 percent of the Reactive Power capability…"** **3) And 4) The VSLs were corrected to fix the discrepancies that you noted.**		
American Transmission Company, LLC		1. Please consider the following comments: Attachment 1, Periodicity for new verification Item 3 - Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or mutually agreed verification date." 2. Attachment 1, Verification Specifications Item 2.1 - There appears to be a typographical error near the end of Item 2.1, we believe that it should state, "Retest the facility within six months of being unable to reach the 90 percent threshold". 3. Attachment 1, Verification Specifications, Item 4.1, Note 1 - Consider deleting the

Organization	Yes or No	Question 4 Comment
		last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner's database and are submitted according to MOD-010.
Response: The GVSDT thanks you for your comment. 1. **The GVSDT believes that a 12 month verification period for new units is more than sufficient and does not believe that verifications beyond this timeline are necessary.** 2. **The sentence was revised as follows: "Reschedule the test of the facility within six months of being able to reach the 90 percent threshold."** 3. **The GVSDT concurs and has removed the last sentence.**		
Ingleside Cogeneration LP		1) Ingleside Cogeneration LP is concerned that there is no apparent provision in MOD-025-2 should a restriction in the extent of Reactive Power validation testing be placed upon the GO or TO by the Transmission Operator. In many cases, the TOP cannot allow the local system to operate beyond a certain Power Factor - especially when the system is supplying reactive power to the generator (leading). It may be the project team's intent that such a limitation is expected to be captured as a "Remark" in the reporting template (Attachment 2). However, we believe that the requirements must include allowable exceptions - as that is what Compliance Authorities will use to assess compliance. 2) Secondly, Measure 1 calls for a Generator Owner to provide correction factors for ambient conditions within 90 days of a request from the Transmission Planner. We agree with the reliability need, but believe there should be corresponding enforceable language in the requirement. 3)In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-025-2, which references generation connected to the "bulk power system"

Organization	Yes or No	Question 4 Comment
		rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: The GVSDT thanks you for your comment. **1) The SDT believes that there are ample provisions in the standard to identify the fact that no limits are to be exceeded. For example attachment 1 - 2.1 refers to “normal (not emergency) expected maximum” Also, the standard requires the submission of the applicable voltage schedule, and lastly, the standard does not require the generating unit to achieve any particular output value, only that it be verified and reported.** **2) The GVSDT has removed “and a correction for ambient conditions, as requested” and added Section 4.2 to Attachment 1 which states “If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later.”** **3) The SDT has replaced references to “bulk power system” with the NERC defined term BES.**		
Independent Electricity System Operator		There is a typo on Row E in Attachment 2: The word “yransformers” should read “transformer”.
Response: The GVSDT thanks you for your comment. The SDT has corrected the mistake.		
Public Service Enterprise Group (PSEG)		1) We have the following additional concerns: a. The entire section 4.2 has language that includes “directly connected to the bulk power system.” The BES is a subset of the BPS per Order 743, and the GVSDT should consult with the SDT for Project 2010-17 - Definition of BES - to develop alternate language that instead refers to the BES. 2) We believe that the addition of section 5.3 (Wind Farm Verification) under the

Organization	Yes or No	Question 4 Comment
		"Effective Date" (section 5 in the standard) is both misplaced and confusing. A paragraph should be written in the "Verification specifications for applicable Facilities" section in Attachment 1 that follows paragraph 1 which would clarify for all generators how the percent verification of applicable Facilities in the "Effective Date" section should be calculated. The following is proposed:"1.1 The percent verification for applicable generating Facilities referenced in the "Effective Date" section of the this standard depends upon how the owner of generating units that are 20 MVA or less and that are part of a plant that is larger than 75 MVA in the aggregate choose to address verification. If the owner verifies the aggregate of all units that are less than 20 MVA as a group, then verification must include all of the aggregate units (i.e., a single applicable facility) taking into account the 90% threshold (which is considered "all") for wind turbines or photovoltaic inverters as provided in paragraph 2.1 below. If the owner verifies each unit that is less than 20 MVA on an individual unit basis, then the percent verification for that plant will be calculated on a unit basis. For example, suppose a plant has 5 units that are 20 MVA or less and 4 units that are greater than 20 MVA at a plant that in aggregate is greater than 75 MVA. If the owner chooses to verify each of the 20 MVA or less units individually, there are 9 applicable Facilities at the plant. If the owner chooses to verify the 5 units that are 20 MVA or less as a group, there are 5 applicable Facilities at the plant - one aggregate "Facility" comprised of 5 units that are 20 MVA plus or less plus 4 units that are greater than 20 MVA." 3) We are concerned with the requirements in Attachment 1 to perform tests, especially Reactive Power capability tests, with the automatic voltage regulator in service (paragraph 2 under the "Verification specifications for applicable Facilities" section) while maintaining the Transmission Operator's voltage schedule and Reactive Power output (see VAR-002-1.1b, R2). Unless R2 in VAR-002-1.1b is temporarily waived for staged tests, it may be impossible to meet paragraph 2.1 under the "Verification specifications for applicable Facilities" section in Attachment 1 since adjusting the Reactive Power output to verify leading and lagging power limits at maximum Real Power output may cause a violation of the cited VAR-002-

Organization	Yes or No	Question 4 Comment
		1.1b requirement. MOD-025-1 needs to address this issue. RFC's standard MOD-025-RFC-1 addresses the issue in its Attachment 1, paragraph 1.2, which states: "If the Reactive Power capability is verified through test, the Generator Owner shall schedule the test with its Transmission Operator. The test shall be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value." 4) Paragraph 2 in Attachment 1's "Verification specifications for applicable Facilities" section has this statement: "Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as that operational data meets the criteria in 2.1 through 2.5 below and is at least 90 percent of a previously staged test that demonstrated at least 50 percent of the capability shown on the associated D-curve." What is meant by "50 percent of the capability shown on the associated D-curve"? Since the D-curve shows both Real and Reactive Power, would a previously staged test be acceptable if it demonstrated only 50 percent of the maximum Real Power capability per the generator's D-Curve? 5) In Paragraph 2.1 in Attachment 1's "Verification specifications for applicable Facilities" section, nuclear units should be exempted from under-excited Reactive Power verification at maximum Real Power capability because such verification may lead to concerns with unit stability and potential under-voltage conditions on internal nuclear plant safety buses. RFC's standard MOD-025-RFC-1 supports this position, since its Attachment 1 states: "Under-excited (leading) Reactive Power capability verification is not required of nuclear units." This sentence should be added to Paragraph 2.1 in Attachment 1. 6) In paragraph 2.2 in Attachment 1's "Verification specifications for applicable Facilities" section, the second sentence excludes nuclear units ("Units" is inappropriately capitalized in the standard this paragraph) from being required to

Organization	Yes or No	Question 4 Comment
		perform Reactive Power tests in paragraph 2.2. For clarity, we suggest that “nuclear” be included in the wind and photovoltaic exceptions in the first sentence, and that the second sentence be deleted. Paragraph 2.2 would thus read “Verify Reactive Power capability of all applicable Facilities, other than nuclear, wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate.” 7) Note 1 in Attachment 1 states: “The verified MVAR value obtained most likely will not be the value entered into the Transmission Planner’s database; nor is it likely this value will agree with data required to be submitted by MOD-010.” If MOD-025-2 data required by Transmission Planners, why wouldn’t the data provided by Generator Owners per MOD-010 for Real and Reactive Power capability be the same data that is developed under MOD-025-1? The SAR for this project stated its purpose: “To ensure that generator models accurately reflect the generator’s capabilities and operating characteristics.

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to “bulk power system” with the NERC defined term BES.

2) The GVSDT removed Section 5.3 and replaced it with a footnote on Section 4.3 “ 1 Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.”

3) The GVSDT has added the suggested paragraph to Attachment 1.

4) These statements refer to the Reactive Power verifications. We have revised the language to clarify this:

“Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted

Organization	Yes or No	Question 4 Comment
(so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification shall be by another staged test, not operational data." 5) If a nuclear unit does not operate under-excited, then the Generator Owner should report that to the Transmission Planner. Several Generator Owners routinely test their nuclear units under-excited. This standard does not require nor expect testing beyond a unit's capabilities and should not test the unit's protective functions. 6) The GVSDT concurs with your comment and has revised the sentence per your suggestion. 7) The sentence was removed from Note 1 and it was revised as follows: "Under some transmission system conditions, the data points obtained by the MVAR verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAR limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2."		
Xcel Energy		Measure M1 says that the Generator Owner must provide evidence that it has supplied the Transmission Planner with temperature corrected values upon request. Making temperature corrections is not stated in the Requirements or the Attachments. In essence, this is creating an additional requirement within the Measure which is not permissible. If the Drafting Team adds a requirement to perform temperature correction, then Xcel Energy strongly recommends that a Technical Reference be added to provide guidance doing the corrections so there is consistency in how the various Generator Owners perform the calculations.
Response: The GVSDT thanks you for your comment. The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was		

Organization	Yes or No	Question 4 Comment
recorded/selected whichever is later." Variations in plant design would make a generic correction procedure extremely difficult. Therefore, the GVSDT feels that ambient conditions corrections should be done on an individual basis by the GO.		
Luminant Power		Luminant agrees with the requirements and activities but suggests that Attachment 1 be modified for clarity as follows (With further clarity, Luminant would be inclined to vote for this standard): 2.1 Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications. 2.1.1 Verify synchronous generating units maximum real power and lagging reactive power for a minimum of one hour.2.1.2 Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Retest the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications. 2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:2.2.1 At minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.2.2.2 At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached. 2.2.3 Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output. 2.3. Delete this section 2.4. Delete this section3.2 Recommend removing this from the Attachment 1 as 3.3 records the high side voltage and from the form (Attachment 2).On Attachment 2, delete "The recorded Mvar values were adjusted to rated generator voltage, where applicable." It is not relevant to the test or the standards scope.Luminant recommends that requirement 4 of Attachment 1 read, "Utilize the

Organization	Yes or No	Question 4 Comment
		simplified one-line diagram ...” Generator Owners can fill in the appropriate quantities at locations A-F. As an example, on some units values would be input for A, B, and F and NA entered for C, D, and E.For Attachment 1, Luminant recommends removing the Notes 1thru 4. This information should be moved to a reference document outside the standard.
Response: The GVSDT thanks you for your comment. **1) The GVSDT concurs with your suggested edits and have incorporated them into the standard. 2) Some AVR’s automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: (1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019. (2) - Transformer Tap Settings - Under “Summary of Verification”, transformer tap settings should be replaced by transformer voltage ratio as tap settings on their own do not provide sufficient information. (3) - Effective Date 5.3 - 5.3 is too specific and should not be a separate sub-section in the Effective Date section. 5.3 should be removed and replaced with a general note explaining how verification percentages should be calculated for wind farms. Suggested wording - “Note - With respect to wind farm sites, the level of completion of verification shall be calculated on the basis of the number of sites, rather than the number of turbines at each site.” (4) - Temperature Range - Manitoba Hydro suggests that the GO should be required

Organization	Yes or No	Question 4 Comment
		to provide a unit's performance in a reasonable temperature range as specified by the Transmission Planner. (5) - Consistency in reference to capability curve - a unit's capability curve is referred to as a D-curve, D-Curve, thermal capability curve, Thermal Capability Curve, and MVAR capability curve in the standard. References to the curve should be consistent. We suggest the curve be referred to as 'Generator Capability Curve'. (6) - Notes 2 and 3 - Notes 2 and 3 should be removed from the standard as they do not seem to be required for compliance purposes and their inclusion creates a lack of clarity. (7) - Data Retention - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to all standards in this project.

Response: The GVSDT thanks you for your comment.

1) The GVSDT matched the implementation times of MOD-025-2 and PRC-019-1 which are closely related standards. These standards are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications.

2) The SDT modified the language to read "Transformer voltage ratio"

3) The GVSDT has removed section 5.3 and incorporated it into a footnote: "[1] Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system."

4) Pertinent ambient condition data is to be recorded in Attachment 2, per Attachment 1, Section 3.4, to be used by the GO, if

Organization	Yes or No	Question 4 Comment
requested by the TP, to modify the Real Power test data to specified ambient conditions other than those at the time of the test. If the TP requests a correction to specific ambient conditions, it would be those conditions representing realistic, normal conditions for that area so that the most realistic Real Power capability can be used in planning studies. 5) The GVSDT has revised all instances to "thermal capability curve (D-curve)" for consistency. 6) Notes 2 and 3 were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located. 7) The Evidence Retention language that you reference is NERC boilerplate language. However, the GVSDT has removed the phrase "and the previous set of evidence if updated since the last compliance audit" from the second paragraph of 1.2 of the Compliance section to correct a conflict between the second paragraph and the bulleted items. The GVSDT feels that the evidence retention period is specified to be since the last audit so the situation you describe could not occur for MOD-025-2.		
Public Utility District No. 1 of Clark County		MOD-025 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60% and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-025. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for your comment. The GVSDT has combined sections 5.1.1 and 5.1.2 so that entities with only one unit will have two years to complete a test.		
Los Angeles Department of Water and Power		Under MOD-025 Attachment 1, "Periodicity for conducting a new verification", Item 2, LADWP believes that the term "operation data" needs to be further clarified. Please provide the methodology and list of data types that qualify as meeting the requirement for verification using historical operational data.

Organization	Yes or No	Question 4 Comment
Response: The GVSDT thanks you for your comment. Operational data, as used in this standard, refers to all of the data that is included in Attachment 2 and recorded by systems such as Plant Information (PI) systems, etc. If all required data had been prerecorded at a time when the testing conditions were met and for the required period, that data may be used as a substitute for a staged test. Note that the operational data used for the Reactive Power verification must have demonstrated at least 90% of a previously staged test that reached at least 50% of the D-curve. If the previously staged test did not reach at least 50% of the D-curve then the next test must also be a staged test. The GVSDT cannot provide a methodology regarding operational data as this would be prescriptive and potentially limit what entities can do to provide data.		
Wisconsin Electric Power Company		1) In Requirement R2.1, the capability is to be verified at the "normal expected maximum Real Power" value. Since the verification cannot always be done in ideal conditions, there needs to be more flexibility in acceptable MW values to account for non-ideal conditions, such as wet coal, for example. A value of "greater than 90 percent of normal expected maximum Real Power" is recommended instead of "normal expected maximum Real Power". 2) Also in Requirement R2.1, the requirement for wind turbines is to have 90 percent of the turbines on-line for the verification. We support having a requirement of 50 percent of rated maximum Real Power, as specified in the ReliabilityFirst regional standard, MOD-025-RFC-01. Using a more attainable requirement for wind turbines will also eliminate the need for re-testing. The standard should have more flexibility for intermittent resources like wind. 3) In Requirement R2.2, the capability is to be verified at the "minimum Real Power output". It may be difficult to operate the unit in a reliable and stable manner exactly at the "minimum" MW value. We suggest allowing more flexibility when verifying at the minimum Real Power value. We propose to allow a range from the minimum Real Power value to the minimum value increased by 10 percent of the rated maximum Real Power. For example, if the maximum Real Power of a generator is 200 MW and the minimum Real Power is 50 MW, the verification for Reactive Power at minimum Real Power could be done anywhere between 50 MW and 70 MW Real Power. This or some other means of providing greater flexibility at

Organization	Yes or No	Question 4 Comment
		the lower end would especially be needed for coal units. 4) In Measure M1, there is a reference to providing values corrected for ambient conditions, if requested. There is no mention of this in the Requirements section. This wording should be deleted, or else any such requirement should be specifically included in the Requirements section. 5) In Attachment 1, 3.1, the values of Real and Reactive Power are to be recorded "at the end of the verification period." It is suggested that the average (mean) values of these quantities over the verification period should be recorded, rather than simply the last value. 6) In Attachment 2, there is a requirement to provide net values at the high-voltage side of the GSU (Point F). This requirement should be deleted. The values for Gross, Auxiliary, and calculated low-side net are sufficient to document the verification. In addition, the required metering at this location may not be available. We have conducted field verifications for five years now, and the low-side values for MW and MVAR have been quite adequate.
Response: The GVSDT thanks you for your comment. **1) The GVSDT provided flexibility in Real Power and Reactive Power testing at full load with the following sentence in Attachment 1 section 2.1: "Verify Real Power capability, Reactive Power capability over-excited (lagging) and Reactive Power capability under-excited (leading) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power at the time of the verifications."** **2) The standard does contain additional flexibility for intermittent resources such as wind to the extent needed. The GVSDT believes that the requirement to have 90% of the wind turbines on line at a particular site is more likely than having the wind site at 50% of its MW capacity. If you have evidence that indicates otherwise please provide that evidence to the GVSDT.** **3) The GVSDT provided flexibility for testing at the minimum Real Power output in Attachment 1 section 2.2 which states: "Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output."**		

Organization	Yes or No	Question 4 Comment
4) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later." **5) It is perceived by the GVSDT that recording data at the end of the test will better represent what the unit is capable of after it has stabilized. In most cases it is expected that data taken at the beginning of the test period and data taken at the end of the test period will be nearly identical. A requirement to average the data would unnecessarily complicate recording and analyzing the test results.** **6) The GVSDT feels that the value injected into the system, the high side net, is the value to be verified. If metering is unavailable, a calculated value may be used.**		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring generator verification of both Real and Reactive Power on a continent-wide level. This standard will also remove the Regional "fill in the blank" obligation to have Regional generator verification requirements. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. 2. Measure M1

Organization	Yes or No	Question 4 Comment
		a. The term "if requested" needs to be removed from the fourth line of Measure M1. The condition of "when requested" is not listed in Requirement R1. 3. VSL Requirement R1 a. The VSLs under the first "OR" statement should reference Attachment 1. This same language should be included in the VSLs for Requirements R2 and R3 as well. Here is an example of a "lower" VSL: "The Generator Owner verified the Real Power capability, per Attachment 1, and submitted the data but was missing 1 to 33 percent of the data. b. The Moderate VSL under the first "OR" statement, should be changed to state "...missing 34 to 66 percent of the data." As currently stated, missing 33% would fall under both the Lower and Moderate VSL category.
Response: The GVSDT thanks you for your comment. **1) The GVSDT has added specific information in the applicability section to account for synchronous condensers, which are not covered by the registry criteria.** **2) The GVSDT has removed "and a correction for ambient conditions, as requested" and added Section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **3a) The proposed revision has been made.** **3b) The VSLs were revised to correct discrepancies with the percentages.**		
Ameren		(1)R1 and R2 require verification of the Real and Reactive Power capability of Applicable Facilities using Attachment 1. Attachment 1 ONLY allows verification by: (a) staged verification, or (b) verification using operational data. We suggest that the GVSDT add an additional option allowing engineering analysis verification.

Organization	Yes or No	Question 4 Comment
		(2) Replace the term "Bulk Power System" with "Bulk Electric System" in Applicability section, items 4.2.1, 4.2.2, and 4.2.3. The use of the term "bulk power system" throughout Section 4.2 Facilities should be replaced with the term "Bulk Electric System (BES)". The use of the term bulk power system, which is not defined in the NERC Glossary, is problematic in determining which generating units and plants must comply with this new Standard. (3)In Note 1 of Attachment 1 to the draft MOD-025-2 standard, it is recognized that, at a given time, one or more generating units under test may not be able to reach full reactive capability as expected based on a review of the unit(s) thermal capability curve due to prevailing transmission system conditions. It is further recognized that the verified reactive power values obtained via testing will likely not agree with the reactive capability as used in model data submitted in compliance with Reliability Standard MOD-010. If it is the intent of this standard to produce reactive power limit data which would be of use for inclusion in powerflow model data, then some means of permitting the generator owner to take the as-tested values and extrapolate to system conditions where full reactive power capability of the generator would be called upon should be allowed. As presently written, MOD-025 Attachment 1 allows only staged testing of the generating units or use of operational data. (4)The Attachment 1, Note 1 refers to the following. (a) The verification values produced by compliance with this new Standard. (b) The manufacturer's D-curve values. (c) The Transmission Planner's database values. (d) The MOD-010 values. Such multiple set of values appear to be in conflict with the purpose of the standard which is, "...ensure accurate information on generator gross and net Real and Reactive Power capability...is available for planning models used to assess Bulk Electric System (BES) reliability"? In this regard we fail to see a need for verification as suggested in this standard. We request the GVSDT to clarify if our interpretation is incorrect. (5)The middle paragraph on page 1 of Attachment 1 requires that any generator that can be operated in both generation mode and synchronous condenser mode must

Organization	Yes or No	Question 4 Comment
		be verified in EACH mode of operation - generation and synchronous condenser. We believe there should be exemptions for small hydro units which in frequently operate in the synchronous condenser mode. (6) Applicable size for the generating facilities in MOD-025-2, MOD-026-1, and MOD-027-1 should be consistent, which is a minimum size of 100 MVA. (7) Rather than a constant 5 year verification cycle, we suggest that the GVSDT consider a 10 year verification cycle with annual confirmation of the most recent verification. The first cycle could make use of the latest MOD-024-1 and MOD-025-1 values. (8) An option should be added for plants with more than one identical unit (sister units) allowing testing for one unit in place of all the identical units. Each cycle the GO should test a different sister unit until all have been tested. (9) Likewise, if MOD-010 data is still required, its requirements should be incorporated into this Standard in the next draft. (10) In the Implementation Plan, with the effective date of this standard, the previous version of related standards should be retired such as MOD-010. (11)Violation Severity Levels - R1 Moderate should be 34 to 66 percent. (12)In the R1 Severe Violation Severity Level, the last paragraph has same time frame shown as the R1 Lower VSL (more than 12 calendar months but less than or equal to 13 calendar months). (13)Violation Severity Levels - R2 Severe last paragraph has same time frame as R2 Lower - similar situation to comment above. (14)Violation Severity Levels - R3 Severe last paragraph has same time frame as R3 Lower - similar situation to comment above.

Response: The GVSDT thanks you for your comment.

1) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. Testing, either

Organization	Yes or No	Question 4 Comment
staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. 2) The SDT has replaced references to "bulk power system" with the NERC defined term BES. 3) Engineering analysis is encouraged. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. 4) Your interpretation is incorrect. Note 1 is for clarification only, contains no requirements, and therefore, does not conflict with the purpose of the standard. The clarification provided by Note 1 is the result of requests for this clarification from previous comments. The Note is suggesting that the capabilities obtained from the verification may not match the D-Curve due to transmission limitations encountered during the test. Verification is needed to identify problems that cannot be discovered from engineering analysis alone such as rotor thermal instability, improper tap settings, inaccurate AVR operation, etc. 5) The GVSDT has removed the requirement for testing in both modes for Facilities capable of being both a generator and a synchronous condenser (see Attachment 1 redline). Such Facilities shall be verified as a generator. 6) MOD-026-1 and MOD-027-1 verify models. MOD-025-1 verifies Real and Reactive capabilities. Although loosely related the purpose of each of these standards is different. The potential for stated capability to be different from the capability that can be verified is large. With this in mind, the GVSDT has no basis to exclude generators that are included in the Registry Criteria and does not believe it is appropriate to do so. 7) The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification. The GVSDT also does not see how an annual confirmation would be less burdensome than a five year re-verification. 8) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. 9) Potential changes to MOD-010-0 should be discussed by that drafting team during the next review for that standard. 10) The possible retirement of MOD-010-0 should be discussed during its next review. 11, 12, 13, 14) We have revised the VSLs to account for discrepancies in the percentages and months as you noted.		
ISO New England Inc.		1) This testing will be difficult to stage due to the four point reactive power testing.

Organization	Yes or No	Question 4 Comment
		The power system will have to be reconfigured in many cases to allow for the changes in generator reactive output. For testing of PV and wind generation, the standard states that at least 90% of the turbines/inverters are "on-line". For reactive testing, would this be better stated as 90% of the plant's capability available, considering some wind turbines maybe be able to produce/absorb reactive power with no real power production, or does on-line just imply that the turbine breaker is closed and no requirement for real power production? 2) In MOD-025 Attachment 2, the definition of Net Real Power Capability was changed (now defined as point F) to exclude Aux or Station Service Real Power connected at the high-side of the generator step-up transformer (point D) and Aux or Station Service Real Power connected at other points of interconnection (point E) with no discussion? Are data required for points D and E or is the MOD only concerned with Gross (point A) and Net (point F)?
Response: The GVSDT thanks you for your comment. **1) The GVSDT does not expect that reconfiguring of the power system would be required to perform the verification. It is recognized that it may be very infrequent that a wind plant is operating above 90% capacity. It is also recognized that many turbines are capable of producing or absorbing reactive power with little or no real power output. It is also recognized that it may be difficult to have all wind turbines available at one time, especially for larger wind plants. With this in mind, a demonstration with 90% of the wind turbines on-line should produce a reasonable approximation of the wind plants capabilities while making it easier to run a test from a logistics standpoint. It is the expectation of the GVSDT for a wind plant that at least 90% of the generator breakers are closed regardless of the MW output.** **2) Attachment 2 is meant to be generic, and applicable for several plant configurations. The desired values are 'net to the BES' which is point F for most configurations. Net values may be calculated values if metering at that point is not available.**		
Alberta Electric System Operator		1. In section 4.2, the AESO considers the existing applicability for reactive power verification to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger.

Organization	Yes or No	Question 4 Comment
		2. Attachment 1, the statements regarding testing the capability of units with a change lasting more than 6 months within 12 months of the change appears to be in conflict with each other. EG: If a change is in place for 7 months but not tested in these 7 months and then issue is rectified how is this change then tested? The time frame for testing cannot exceed the time that change is in effect, or some qualifying language needs to be added.
Response: The GVSDT thanks you for your comment. The GVSDT is not able to justify including units outside the definition for the BES and Registry Criteria nor do we believe it is appropriate to do so. It is possible for WECC to create more stringent regional criteria to include the units you suggest if needed.		
TransAlta Centralia Generation LLC		The Transmission Operator (System Operator) should be included as an applicable functional entity since the Reactive Power verification test will to be coordinated by Transmission Operator (System Operator). There should be a requirement assigned to TOP for such coordination.
Response: The GVSDT thanks you for your comment. In accordance with the NERC reliability function model, Transmission Planners are required to report its planning results to Transmission Operators and because of this, the GVSDT does not believe the Transmission Operators need to be added to this standard.		
Seattle City Light		Attachment 1 "Verification specifications for applicable Facilities:" section 2.3: It will be difficult to test at maximum power for one continuous hour at some plants due to operating restrictions regarding water flow or other factors.
Response: The GVSDT thanks you for your comment. In Attachment 1 "Verification specifications for applicable Facilities:" Section 2.1 it states in part, "Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification." If the test can't be run at maximum power for one hour it is expected that the maximum power that can be sustained for one hour will be used for the verification.		
Cowlitz County PUD		1) Cowlitz understands the SDT must comply with FERC directive in Paragraph 1321. However, Cowlitz disagrees that requiring verification every five years will not be too

Organization	Yes or No	Question 4 Comment
		burdensome to the GO. Cowlitz is not confident that verification will be possible with operational data, and will be forced to verify via staged verification for at least two of the test points. We suggest that staged verification for four test points be required every 10 years with operational verification within 10% of at least one test point from the last staged verification being made no greater than 5 years after the staged verification. Should all four staged test points be confirmed via operational verification within 5 years of the last staged verification, then staged verification will reset to 10 years. If operational verification can't be provided within 5 years of the last staged verification, then one point must be verified via staged verification 5 years after the last full staged verification (all 4 points). 2) Cowlitz also disagrees with the generation applicability set at 20 MVA. This is arbitrary; FERC made no mandate in this regard and in fact shared a "concern with several commenters that such a requirement for all [Registered] generators may not be necessary." Cowlitz respectfully points out that it appears the SDT made no effort at all to determine true Reliability impact. Drafting Reliability requirements with no Reliability return must be avoided. SDT statements that simply state "the effort is not considered to be costly or burdensome" is not acceptable as it only offers an opinion without substantiating evidence.
Response: The GVSDT thanks you for your comment. **1) It is expected that some staged verifications will be required. The GVSDT believes that due to the many factors that can affect Reactive Power capability, five years is the correct periodicity for re-verification.** **2) The GVSDT has no evidence to exclude any registered generators from the requirements of MOD-025-2 nor do we believe that it is appropriate to do so. If Cowlitz County PUD has evidence it can share to suggest otherwise please provide that evidence.**		
American Electric Power		1) In section 4.2 for Facilities , the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC.

Organization	Yes or No	Question 4 Comment
		2) Item 5.3 appears to be one exclusive example. What if there are three wind farm sites? AEP agrees with the example given, but 5.3 should contain a high-level statement followed by the example provided. 3) We still oppose using language requiring that a standard be effective by "the first day of the first calendar quarter" x "calendar years following applicable regulatory approval". It is not clear exactly how this is to be interpreted. For example, if regulatory approval is granted on Feb 1 2013, is the standard effective on Jan 1 2014 or April 1 2014 if "x" is one year? For the effective date, we recommend not mixing years and quarters. Instead, we recommend that the total number of quarters be used, otherwise it is unclear if the effective date is the quarter following the year or the quarter at the end of that year.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:** **[1]Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.** **3) The SDT has used language in the Effective Dates section that is consistent with many other standards and believes it to be clear.**		
Exelon		1) As stated in the previous comments from Exelon to Questions 5, 7, 12, 13 and 14 as documented in the Consideration of Comments on Generator Verification (MOD-025-2) - Project 2007-09 dated 2/22/12 (p81, p106, p150, p156 and p189), Nuclear units should not be required to perform under-excited (leading) reactive capability verification testing due to concerns with unit stability and potential under voltage conditions on internal nuclear plant safety buses that may challenge safe plant operations and could lead to a plant transient or shutdown in accordance with NRC operating license. In response to Exelon's comments on Questions 5, 7, and 14 the

Organization	Yes or No	Question 4 Comment
		SDT states that [a nuclear plant] "should be tested within the unit's capability and declared safety margins. The standard does not require challenging unit capabilities." In addition, the statement "Auxiliary bus voltage limits should be observed" was added to Note 1 of Attachment 1. As further stated in Summary Consideration for Question 5, the SDT has added Note 4 to Attachment 1 that states that "The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability, then it should be reported with no leading capability, or the minimum lagging capability at which it can operate."Exelon requests that this note be further clarified as follows:"The verification is intended to define the limits of the unit's capabilities. If a unit has no leading capability or the unit is restricted due to other regulatory, unit stability or other potential equipment restrictions then it should be reported with no leading capability, or the minimum lagging capability at which it can operate." In response to Questions 12 and 13 to Exelon's comments, the SDT further states that "Nuclear units are not required to perform Reactive Power verification at minimum Real Power output" as currently stated in Attachment 1 Verification Specification 2.2. Exelon requests this be revised to clearly state that nuclear units should also not be required to perform under-excited (leading) reactive capability verification. Attachment 1 Verification Specification 2.2 should be revised as follows:2.2. Verify Reactive Power capability of all Applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability at the minimum Real Power output at which they are normally expected to operate. Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output and are not required to perform under-excited (leading) Reactive Power verification. 2) With respect to all of the Notes provided on the current draft MOD-025 Attachment 1, Exelon requests that the Notes be tied to the verification specification that they are referring to. 3) Historically Exelon has noted that its larger generating units have not been able to attain all of the data necessary for an over-excited full load and minimum load reactive power verification on the same test day due to grid constraints. Please

Organization	Yes or No	Question 4 Comment
		clarify that it is acceptable to perform segments of the reactive power verification on different test days as long as each portion of the test is performed for the required duration. 4) Please explain what is meant by the statement "[T]he recorded Mvar values were adjusted to rated generator voltage, where applicable" in the Summary of Verification section of Attachment 2. 5) The last Section of MOD-025-2 Attachment 2 requires certain Verification Data to be provided by unit or Facility, as appropriate. Exelon suggests that both the "rated" and "as tested" generator hydrogen pressure values be recorded as a comparison. Suggest the following be added to the Summary of Verification in Attachment 2: o Generator hydrogen pressure (if applicable)Rated pressure: _____________As tested pressure: _____________ 6) In the Consideration of Comments on Generator Verification (MOD-025-2) - Project 2007-09 dated 2/22/12 (p12), the SDT responded to the industry that it anticipated that Regional Standards would be retired once MOD-025-2 is approved. In addition, the SDT added language specifically to the Implementation plan to address the intent of ReliabilityFirst (RFC) to perform a review of both MOD-024-RFC-01 and MOD-025-RFC-01 standards upon NERC BOT approval of NERC MOD-025-2. RFC has recently announced that they are “suspending Regional Standards efforts.” On the NERC website MOD-024-RFC-01 is RFC Board Approved and MOD-025-RFC-01 is NERC BOT Adopted. Exelon is unsure of the status of both MOD-024-RFC-01 and MOD-025-RFC-01. With respect to the wording added to the Implementation Plan for MOD-025-2; what is the status of the intended review by RFC of both Regional Standards upon NERC BOT approval of the associated NERC MOD-025-2 Standard?

Response: The GVSDT thanks you for your comment.

1) The GVSDT disagrees with not requiring a verification to define the unit’s reactive capability. A full load lagging capability verification does not adequately define the unit’s reactive capability. The GVSDT believes that a nuclear unit can be tested at full load in both lagging and leading capability within the safe operating limits of the unit and reaffirms that challenging the plant’s

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">safety systems is not required by this standard. The GVSDT is aware of nuclear units that have been safely tested to their leading power factor limits. This standard does not restrict an entity from declaring that a unit has no leading power factor capability if it has determined that leading power factor capability does not exist. The limitations can be described in the “Remarks” section of Attachment 2.

2) The Notes were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1 and where to place them. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Therefore, the notes will remain where they are presently located.

3) The GVSDT confirms that testing different points at different times is allowed and may be necessary as you suggest. Attachment 1, Periodicity section, has been revised for clarification.

4) Some AVR’s automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage.   To eliminate confusion the reference to this adjustment has been removed from Attachment 2.

5) The SDT has revised the item to “Generator hydrogen pressure at time of test (if applicable) _____________”. The GVSDT believes that this clarifies the data required and eliminates any possible confusion.

6) It is the understanding of the GVSDT that RFC has approved the standards but has not filed them for regulatory approval pending approval of MOD-025-2. RFC will re-evaluate the two standards upon approval of MOD-025-2 and will make revisions and / or retirements as necessary.</td></tr>
<tr><td>Texas Reliability Entity</td><td></td><td>1)Facilities--Avoid use of “bulk power system.” There is inconsistency between the Standards in this Project with regard to applicable Facilities. Suggest using BES definitions or Transmission Planner requirements (if TP requirements are inclusive of BES as a minimum).

2)Effective date 5.3: “Wind site” is not defined.</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		3)Seasonal considerations for Real and Reactive Power do not appear to be considered in this Standard. This could be detrimental to use in Planning models for specific periods. 4)It is unclear whether this Standard requires Gross or Net (or both) capabilities to be verified. The Attachments seem to allow for either, to some degree, but is not definitive. It should be clearly stated which is expected.The following comments refer to the Attachment 1: 5)In Attachment 1 the term “commercial operation date” is used. The phrase should be more along the lines of “initial synchronization to grid,” as a commercial operation date may be an extended time from initial synchronization. In general, there would be manufacturer’s data that may be used in models but it is critical to understand the capabilities early on. 6)How does one determine what changes are “expected” to make a 10 percent change in last reported capability? We suggest deleting “is expected to.” 7)Attachment 1 item 2.1: We recommend changing the real/reactive power capability test to be conducted at 95% or higher of the expected maximum Real Power gross output. Also, we recommend changing the first sentence as follows: “Verify gross and net Real Power capability, gross and net Reactive Power capability over-excited (lagging) and gross and net Reactive Power capability under-excited (leading)......”. 8)Attachment 1 item 2.2 appears to allow wind and photovoltaic “applicable facilities” to not have to verify Reactive Power capability at a minimum Real Power output. Is that the expectation of the SDT? At least in 2.1 there were statements regarding what was expected of wind and photovoltaic Facilities for Real and Reactive Power at expected maximum Real Power “at time of the verifications.” 9)Attachment 1 item 2.3: What is the basis for “one continuous hour?” What is the expected value(s) to be provided for the continuous hour of verification (i.e. an instantaneous value, an integrated value, or average value)? Variability in solar and

Organization	Yes or No	Question 4 Comment
		wind turbines may not allow for a full hour. Additionally, system conditions must be taken into effect for tests (disturbances that do not necessarily put the system into an emergency situation but may impact capability). Current ERCOT regional criteria for the Reactive Power leading and lagging tests is 15-minutes. 10)Attachment 1 item 2.4: Is this meant to be an instantaneous value to be collected? Or do the units have to maintain the verified value for an hour? Is the intent of 2.4 captured in 3.1 (as 3.1 appears to be a value recorded at the end of the verification period)? 11)Attachment 1 Section 3 does not include all the measurements shown in Attachment 2. While Form 2 may be changed (hopefully under the direction/guidance of the TP), section 3 should at least capture what measurements are portrayed in the Attachment 2 form as it exists. 12)Attachment 1 item 3.2: This is unclear regarding seasonal expectations and how to capture those expectations in a verification activity. As written, this Standard will only capture one season and may not facilitate proper use of the data in Planning models. In ERCOT, resource entities currently provide minimum and maximum seasonal capabilities for Fall, Winter, Spring, and Summer. We would suggest that, as a minimum, this Standard should require Real and Reactive capabilities for the Winter and Summer seasons. 13)Attachment 1 items 3.3 and 3.6: “Interconnection” should not be capitalized. 14)Attachment 1 item 3.4: Should include “Others as applicable” to match Verification Data form. 15)Attachment 1 item 3.8 is not captured on Verification Data form. 16)Change MVAR to Mvar in the “Notes” section of Attachment 1.Attachment 2 17)The first part of Attachment 2 assumes a single point of interconnection (Point F). Should there just be a requirement to supply a detailed one-line with measurement points noted and remove the sample one-lines?

Organization	Yes or No	Question 4 Comment
		18)In the Verification Data form, the use of the phrase “connected at the same bus” may have different interpretations than expected. Suggest removing the phrase or at a minimum changing the phrase to “measured at sites connected to the low side voltage level(s) of the GSU”. It should be noted that Auxiliary and tertiary loads (in terms of Real and Reactive Power) are not necessarily “connected at the same bus.” 19)Why is “N/A” in a few locations on the Verification Data form? 20)Please change the Verification Data form to use the same terms in the definitions of Net Reactive and Net Real Power (form calls for Gross Reactive Power Generating Capability” but definitions of Net do not use same term). VSLs 21)VSLs for R1- Suggest matching the language of the requirement with regard to “date the data is recorded for a staged test” or to the changes suggested for R1 (“date of a” staged test). 22)VSLs for R1- Suggest matching the language of the requirement with regard to “the date of the historical operating data that was selected.” The Requirement states “the date the data is selected for verification using historical operational data” which may be different than the date of the historical operating data (that was selected). 23)VSLs for R1- The second “OR” statement is not auditable if the Verification Data form is allowed to be changed. If the form had a minimum data requirement that had to be provided, a VSL could be created. As written, the statement “The Generator Owner verified the Real Power capability and submitted the data but was missing 1 to 33 percent of the data” and variations thereof cannot be audited. 24)VSLs for R1- Suggest adding “Real Power” in the third and fourth “Or” statements as R1 only refers to Real Power-“The Generator Owner performed the Real Power verification...” 25)Severe VSL for R1- The last “OR” statement needs corrected as it is the same

Organization	Yes or No	Question 4 Comment
		language for the Lower VSL. Suggest changing to the following: "The Generator Owner performed the verification per Attachment 1, "Periodicity for conducting a new verification" item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months. " 26)R2 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. 27)R3 VSLs have the same comments as R1 VSL with the exception of adding "Reactive Power" instead of "Real Power" in the suggested locations. Additionally, there are multiple references to "Generator Owner" that should be replaced with "Transmission Owner."

Response: The GVSDT thanks you for your comment.

1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.

2) The SDT has removed section 5.3 (Effective Date) and replaced it with a footnote as follows:

[1]Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

3) In Attachment 1, Section 3.4, the Generator Owner is required to record the data needed to make corrections for different ambient conditions. If a Transmission Planner requests corrected test results for specific ambient conditions the recorded data can be used to provide that information.

4) The table in Attachment 2 requests net capabilities. This is the desired verification. Other values are collected to support obtaining the net values.

5) Twelve months from "commercial operation date" is deemed to be sufficient by the GVSDT. Using the first date the unit synchronized to the grid may be problematic as there could be an extended period of time when other issues could prevent verification testing.

6) The GVSDT concurs and has made the revision.

7) The GVSDT at one point considered allowing Reactive Power full load testing to be at least 95% of rated full load MW's but with

Organization	Yes or No	Question 4 Comment
		the merger of MOD-024-2 into MOD-025-2 it was determined that allowing a Real Power test at 95% of full load MW's was not justified and would only add confusion. In addition the wider spread between full load and minimum load test points for Reactive Power capability provides a better approximation of the capability curve. 8) It is the intent of the GVSDT to not require Reactive Power testing of wind and photovoltaic plants at more than one Real Power output. The characteristics of the plants, and difficulty reaching a maximum or minimum load diminishes any benefits of the additional test. 9) One continuous hour was established as a minimum time for verification to verify that there are no equipment related issues with operating at the verification levels. 10) Section 2 of Attachment 1 has been revised in response to several commenters. The Reactive capability values now specified to be recorded are instantaneous values as indicated in revised section 2.2. 11) Attachment 2 was developed to account for different configurations and not all data will need to be recorded for every configuration or verification. The intent is to be able to develop a net Real and Reactive Power output for applicable Facilities. 12) In Attachment 1, Section 3.4, the Generator Owner is required to record the data needed to make corrections for different ambient conditions. If a Transmission Planner requests corrected test results for specific ambient conditions the recorded data can be used to provide that information. 13) The SDT agrees and has made the changes you suggest. 14) Attachment 1 Section 3.4 includes the phrase "such as" before the list indicating it is not a complete list. We also added a bullet "Other data as applicable" to Section 3.4. With this, the SDT believes it is compatible with Attachment 2. 15) The check boxes in Attachment 2 include Operational Data and Staged Test Data check boxes. These represent what is listed in Attachment 1 Section 3.8 16) The SDT agrees and has made the changes you suggest. 17) The diagram is meant to be generic, and represent several possible topologies. Generator Owners may use their own diagram if they wish as long as it supplies the required information. Parts of the diagram that do not apply to your particular site are to be left blank or marked N/A. 18) The commenter has not provided a description what alternative interpretation of "connected at the same bus' they believe will occur. This makes it difficult to respond to the comment. The GVSDT believe that language is clear.

Organization	Yes or No	Question 4 Comment
19) We have removed these instances. **20) We have removed the word "generating" from the term "Gross Reactive Power Generating Capability (*Mvar)" and Gross Real Power Generating Capability (*Mvar).** **21) The SDT agrees and has made the changes you suggest to the VSLs.** **22) The SDT agrees and has made the changes you suggest to the VSLs.** **23) The note to Attachment 2 allows changes to the form but requires that "all required information is reported". Since this is included the VSL should be valid.** **24) The SDT agrees and has made the changes you suggest to the VSLs.** **25) We have revised the VSLs to account for discrepancies in the months as you noted.** **26) The SDT agrees and has made the changes you suggest to the VSLs.** **27) The SDT agrees and has made the changes you suggest to the VSLs.**		
Entergy Services, Inc	Yes	1) VAR-002-1.1b Requirement R1 states "The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator." However, proposed MOD-025-2 allows testing to be conducted in another mode (see MOD-025-2 Attachment 1 verification specifications item 2 and accompanying Note 3). The majority of generators connected to the bulk power system are operated in automatic-controlling voltage. A lesser number may be operated in automatic-var control or automatic-power factor control. A smaller number may be operated in manual. In these different modes, there are different excitation system protective features that are enabled or disabled. Therefore, unless generators are tested in the mode in which they normally operate, it is difficult to verify that some protection system limit will not be encountered. It is important for the Transmission Planner to model the unit with capabilities and limitations that would exist during normal operations. Entergy recommends that MOD-025-2 Attachment 1 verification

Organization	Yes or No	Question 4 Comment
		specifications item 2 and accompanying Note 3 be revised to require that generators be tested in the mode in which they normally operate. In fact, Note 3 should be eliminated and the Entergy recommendation incorporated into specification item 2 alone since it is not necessary to caution the GO about exceeding machine limits in the standard. 2) On Attachment 2 Comment Section for Point A, add note that "individual unit values are required for units > 20 MVA. (This is required by Attachment 1 verification specifications item 2) 3) On Attachment 1, item 2.6, add sentence stating that "GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary." If the generator current or MVA is known, transformer losses can be estimated with sufficient accuracy for modeling use by the Transmission Planner. 4) On Attachment 1, verification via testing of a sister unit located at the same generating plant should be allowed. A number of generating plants consist of multiple identical units. If this is the case, and it can be established that no modifications have been made which would negate this sister unit status, it should be allowed to test one of the units and take credit for the results for the other units. Requiring that this be limited to units at the same plant location accounts for differences in transmission grid configuration, maintenance practices, and similar. 5) Entergy recommends that the SDT establish consistency across standard drafts (MOD-025, MOD-026, PRC-019 and MOD-027) as to items such as minimum plant size (75 MVA vs. 100 MVA) and use of "sister unit" concept. This will facilitate more consistent unit verifications. 6) Entergy agrees with having separate requirements for real and reactive power. However, MOD-25-2 requires that reactive power testing be repeated every five years (in the Periodicity section of Attachment 1). This effectively means that each GO with a large number of units will be in a perpetual state of performing the 20% per year required for initial validation. Where staged reactive power testing is

Organization	Yes or No	Question 4 Comment
		necessary, this is an intrusive test for both the unit and the grid that places an undue burden on both generator operators and transmission system operators. Additionally, such testing is not without risks. Recommend that, after initial validation, repeat testing only be required if there is a long-term plant configuration change, a major equipment change, power system topology changes, or similar changes which impact the reactive testing results. 7) Since testing will not typically provide good estimates of actual VAR capacity (although possible with excellent planning/generator coordination), some level of engineering analysis will be required to produce true VAR estimates (the purpose of this standard). Therefore, such analysis should be required unless testing produces adequate planning values for VAR capabilities.

Response: The GVSDT thanks you for your comment.

1) The GVSDT does not intend for a unit to change voltage regulator control modes in order to complete testing but simply makes it clear that testing is still to be done if the automatic voltage regulator is either not used or not available. It would be preferred that the test be rescheduled for a time when the automatic voltage regulator is operational if possible. Coordination of limiters with protection and generating unit capabilities is not the intent of this standard. Please reference PRC-019-1. MOD-025-2 also does not require operation outside the capabilities of the unit. The Notes were added at the request of stakeholder comments to add clarifying information regarding the verification requirements. The GVSDT received conflicting comments concerning the Notes in Attachment 1. The team believes that the notes, while not requirements, are important clarifying information that needs to remain in the standard. The drafting team is concerned that the notes will be lost if moved to a guidance document or elsewhere. Note 3 has been modified to eliminate the caution about not exceeding machine limits if in manual voltage control.

2) The GVSDT agrees and has made this change.

3) Attachment 1, 2.6 has been modified for clarity.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

4) The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units.

Organization	Yes or No	Question 4 Comment
5) Standards MOD-025-2 and PRC-019-1 are closely related and have been matched as closely as possible for consistency. These two standards, however, are not closely related in either content or complexity to MOD-026-1 and MOD-027-1. MOD-026-1 and MOD-027-1 are verifying AVR and governor models which do not change as frequently as reactive capabilities or setting coordination potentially could and, therefore, would have a longer period between re-verifications. The intent of testing all units is to discover unintended differences or deficiencies with unit capabilities or control systems that can only be identified by testing all units, including sister units. **6) After the first staged test operational testing is allowed and further staged testing may not be required. Either operational or staged testing is intended to identify problems that cannot be identified by plant configuration change, major equipment changes, power system topology changes, or similar changes which impact the reactive testing results.** **7) Engineering analysis is encouraged though not required if testing does not produce adequate planning values. For utilities that do not have the means to do engineering analysis the alternatives would either be to declare the capability they can verify or to hire a consultant to do the engineering analysis.**		
Duke Energy		1) R1 requires the Generator Owner to verify Real Power capability per Attachment 1, and submit the data per Attachment 2. While Section 3.4 of Attachment 1 requires collection of ambient condition measurements needed to perform corrections to Real Power for different ambient conditions, MOD-025-2 doesn't require that the Generator Owner make corrections for specific conditions (such as summer peak day, etc.), and also doesn't provide for the Transmission Planner to request verification for any conditions other than whatever conditions existed during the verification required by this standard. Measure M1 indicates that the Generator Owner is to submit a correction for ambient conditions, if requested, but that's not included in R1, Attachment 1 or Attachment 2. MOD-025-2 should either specify the conditions for which the Generator Owner must make corrections to real power, or should require the GO to make corrections to any conditions when specified/requested by the TP/TOP. A requirement should be added for the Generator Owner to provide the Transmission Planner with verification of Real Power capability for different ambient conditions within 90 days of a request by the Transmission Planner.

Organization	Yes or No	Question 4 Comment
		2) R2 requires the Generator Owner to verify Reactive Power capability per Attachment 1, and submit the data per Attachment 2. Note 1 and Note 2 on Attachment 1 are commentary on the meaning of the test results and imply additional analyses is expected but provide no explicit directions that must be taken. Note 1 recognizes that the value of the testing may be limited to uncovering MVAR limitations. Note 2 is a commentary that encourages the Generator owner to perform engineering analyses, but the expectations are unclear. MOD-025-2 must clearly describe what engineering analyses are to be performed, what operational data is required to support the analyses, and the deliverables of this effort. MOD-025-2 should be made more specific regarding acceptable system conditions for collecting test or operational data, and the extent to which engineering analysis is required for model verification. SERC developed a generator model validation guide in ~ 2004, which laid out a process where an engineering review and operating data should be performed first and then testing might be done on a limited basis if needed to capture data not covered by an operational review. The SDT could leverage that guide to better understand the approach, which was agreed to by the region's planning and generator operators. 3) Attachment 2, Summary of Verification - Strike the fifth bullet (The recorded Mvar values were adjusted to rated generator voltage, where applicable.) o Applicability Section - change "bulk power system" to "BES".

Response: The GVSDT thanks you for your comment.

1) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."

2) Engineering analysis in encouraged though not required by this standard. Engineering analysis may reveal additional MVAR capability that is not able to be demonstrated during a verification test and can be presented to the TP for consideration. It is

Organization	Yes or No	Question 4 Comment
usually most desirable to perform overexcited tests when the system voltage is low and underexcited tests when the system voltage is high. System conditions may not play as big of a role if there are other units or reactive resources nearby to counter the Reactive Power generated or absorbed for the test. The operational data that would be used to assist in the engineering analysis is the same data required for a staged test (see Attachment 1, 3.1 through 3.8). Again, the engineering review that you suggest is encouraged though not required because many utilities may not have the resources to perform such analysis. Testing, either staged or from operational data, is needed to identify problems that cannot be discovered from engineering analysis alone. **3) Some AVR's automatically adjust MVAR limits to a more restrictive value when the generator is operating below rated voltage appearing as though it is set improperly while testing. During times of system need for underexcited VARs the voltage is not expected to be low and therefore, the expected capability would be the tested value corrected for rated voltage. To eliminate confusion the reference to this adjustment has been removed from Attachment 2.**		
American Wind Energy Association		Overall, the draft standard is well-drafted and well help to improve reliability, and I would like to see it pass this round of balloting. If there is another round of revisions to this draft standard, it may make sense to look at this recently added section to make sure that it is a workable requirement for all wind projects: "If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, the Generator Owner must document the reasons it was unable to meet the threshold and test to the full capability at the time of the test. The Generator Owner shall retest the Facility within six months of being able to reach the 90 percent threshold." For some wind plants, it may be difficult to schedule a test or retest at a time when 90% of the wind turbines are producing. Some wind plants may have significant periods of time when they have fewer than 90% of their wind turbines producing for reasons beyond their control (wind resource availability), and it is typically not possible to predict when those time periods will occur more than a day or two in advance. Repeated attempts at retests until one coincides with a period of sufficient wind resources may not be the most efficient process for testing a plant. Obtaining additional input from wind plant owners would help to clarify this issue, and if that input indicates a concern, the drafting team may want to change the 90% threshold or provide additional flexibility in the testing process to ensure that this standard will be workable for all wind

Organization	Yes or No	Question 4 Comment
		projects.
Response: The GVSDT thanks you for your comment. It is also recognized that it may be difficult to have all wind turbines available at one time, especially for larger wind plants. With this in mind, a demonstration with 90% of the wind turbines on-line should produce a reasonable approximation of the wind plants capabilities while making it easier to run a test from a logistics standpoint. It is the expectation of the GVSDT for a wind plant that at least 90% of the generator breakers are closed regardless of the MW output.		
Indiana Municipal Power Agency		1)Under 4.2 Facilities, IMPA recommends replacing bulk power system with Bulk Electric System which is used in NERC Standards. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)M1 states that the Generator Owner will have evidence that it submitted a correction for ambient conditions. In requirement 1, it does not state that the Generator Owner shall submit a correction for ambient conditions. Either requirement 1 or Measure 1 needs to be corrected to the intent of the SDT. 3)While realizing that the field or armature may be the limiting component in certain segments of the a generator’s capability curve, IMPA does not see any value in making a generating unit verify its under-excited Reactive Power capability and over-excited Reactive Power capability at minimum Real Power. Operation at these points at minimum Real Power will seldom if ever happen. IMPA recommends deleting the requirements for reactive capability at minimum Real Power. 4)When at maximum Real Power, it is not clear what over-excited Reactive Power level a generating unit is to maintain for an hour when at maximum Real Power to constitute an acceptable test. IMPA believes in many instances units will reach a limit, such as volts per hertz, and will not be able to reach the over-excited reactive power curve. A Reactive Power test should be acceptable as long as it stays at a documented, reached limit for an hour and should not be required to retest within 6 months. IMPA recommends that the SDT makes its intent clear on what constitutes an acceptable test when at maximum Real Power and over-excited Reactive Power

Organization	Yes or No	Question 4 Comment
		capability.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT has removed "and a correction for ambient conditions, as requested" and added section 4.2 to Attachment 1 which states "If an adjustment is requested by the TP develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator at different conditions, such as peak summer conditions, can be determined. Adjust MW values tested to ambient conditions specified by the TP upon request and submit them to the TP within 90 days of the request or the date the data was recorded/selected whichever is later."** **3) FERC Order 693 requires verification at multiple points, and the GVSDT believes that verification at a minimum of four points is necessary to approximate the capability curve.** **4) The level of Reactive Power is unimportant for a Real Power test. If doing both the Real Power and a Reactive Power test at the same time, the unit should be operated at the maximum attainable Reactive Power (lagging), at normal (not emergency) expected maximum Real Power, for one hour to be considered a valid Reactive Power test. The limiting factor should be recorded after one hour per Attachment 2. The stabilization period of one hour applies to both the Real Power test and the Reactive Power (lagging) tests only. If doing the two tests at the same time the stabilization periods run concurrently.**		
Kansas City Power & Light		Should replace "bulk power system" with "Bulk Electric System". Use of "bulk power system" is ambiguous where as "Bulk Electric System" is fully defined.
Response: The GVSDT thanks you for your comment. The SDT has replaced references to "bulk power system" with the NERC defined term BES.		
MRO NSRF		1) In the applicability section reference is made to bulk power system which is an defined term. To avoid confusion as to which generating units are required to comply with this standard, use of the defined term, Bulk Electric System, is recommended. The purpose of MOD-025-2 refers to the "BES reliability" but Facilities listed within 4.2, speak of generation units connected to the BPS. This

Organization	Yes or No	Question 4 Comment
		difference of term does not provide consistency within this proposed Standard. The BES Drafting Team has established a set of "inclusions" that will "pull in" generation units that may not be connected to the BES. 2) Attachment 1, Periodicity for new verification Item 3 – Allow for mutually agreed on flexibility by adding the wording at the end of the sentence like, ". . . or mutually agreed verification date between the Generator Owner and Transmission Planner" 3) Attachment 1, Verification Specifications, Item 4.1, Note 1 – Consider deleting the last sentence because it contradicts the purpose of the standard, contracts the sentiment of Note 2, and will likely to be untrue after verified values are entered into the Transmission Planner's database and are submitted according to MOD-010. Please clarify the purpose of this statement.
Response: The GVSDT thanks you for your comment. **1) The SDT has replaced references to "bulk power system" with the NERC defined term BES.** **2) The GVSDT believes that a 12 month verification period for new units is more than sufficient and does not believe that verifications beyond this timeline are necessary.** **3) The GVSDT concurs and has removed the last sentence.**		
Pepco Holdings Inc and Affiliates		No comment
Tacoma Power		None
Dynegy		No
Oncor Electric Delivery		No

Organization	Yes or No	Question 4 Comment
Company		

MOD-027 Overall Summary Consideration: The GVSDT received valuable feedback from stakeholders suggesting improvements to the standard.

Most stakeholders agreed with the inclusion of partial load rejection testing and the inclusion of the applicable footnote. As many stakeholders noted, the appropriate footnote in the posted version of the standard was footnote 4, rather than 5 – and is currently footnote 2 in the current draft of the standard. Based on the comments received, the GVSDT made the following clarifications and revisions:

1) **Numerous revisions made to clarify the language in Attachment 1, including adding row numbers. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.**
2) **Revised sections 4.2.1, 4.2.2, and 4.2.3 to clarify the language.**
3) **Corrected numbering error of footnotes 4 and 5.**
4) **Corrected language in the footnote associated with partial load rejection, changing "on-load data" to "on-line data"**
5) **Reformatted sub part 2.1.1 that breaks the three alternatives for acquiring the unit MW response for model verification into 3 bullets instead of listing all three in a sentence.**

Stakeholders were evenly divided in their opinions regarding the periodicity aspects of Attachment 1. The GVSDT received suggestions for improvements which include the following:

1) **Numerous revisions were made to clarify the language in Attachment 1.**
2) **Row numbers were added to Attachment 1.**
3) **The following text was removed from R2: "within 365 calendar days from the date that the response was recorded".**
4) **In Attachment 1, the column title was revised from "Comments" to "Required Action".**
5) **Removed 25/50/75/100% phase in allowing GOs to install MW Recorders. This phase in unnecessarily complicated the Implementation Plan considering the vast majority of units already have recorders or processes in place where MW response can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that low resolution data, approximately one sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.**

There was a lot of industry confusion regarding the GVSDT attempt to effectively propose an exemption for base load units as the term "base load units" per say did not appear in the draft of the standard. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.

Stakeholders provided many suggestions for revisions to the standard. The following revisions were made by the GVSDT:

1) **A significant number of industry commenters opposed the use of the term "bulk power system" in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as "bulk power system" is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
2) **For clarity and ease of reading, a paragraph within R3 was moved to the end of the requirement.**
3) **Changed "facility" to "unit" in Measures 2 and 4 to match the terminology in the requirements. Also, other minor clarifications and edits made in the Measures.**
4) **Changed "and" to "or" everywhere the phrase "and active power/frequency control functions" appears.**
5) **Revised R2 to remove "within 365 calendar days ......"**
6) **Revised R2.1.1 to specify "unit's MW model response".**
7) **Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the entity performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.**
8) **Revised Attachment 1 extensively for clarity, including removing specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
9) **Revised the Effective Dates, and subsequently the Implementation Plan, to mirror the Effective Dates in the current draft of MOD-026 (verification of Excitation Control Systems).**
10) **Removed an extra word "that" (just before the word accurately) in the Purpose statement.**
11) **The qualifier "directly connected" was applied at the top level of the Facilities section (A4.2) to emphasize direct connection to the BES.**
12) **The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.**
13) **The SDT revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 5)**

5. The GVSDT has included partial load rejection testing in Part 2.1.1 subject to the conditions specified in footnote 5 (differences between the control mode tested and the final simulation model must be taken into account). Do you agree with the inclusion and footnote 5? If not, please explain in the comment area below.

Summary Consideration: Most stakeholders agreed with the inclusion of partial load rejection testing and the inclusion of the applicable footnote. As many stakeholders noted, the appropriate footnote is footnote 4, rather than 5. Based on the comments received, the GVSDT made the following clarifications and revisions:

1) Numerous revisions were made to clarify the language in Attachment 1, including adding row numbers. Several Industry commenters indicated that it was not clear if the table was associated with Attachment 1 or not. In response, the SDT has re-formatted Attachment 1 to make it clear that the table is a part of Attachment 1.

2) Revised sections 4.2.1, 4.2.2, and 4.2.3 to clarify the language.

3) Corrected numbering error of footnotes 4 and 5 (in current draft of the standard, the partial load rejection footnote is Footnote 2).

4) Corrected language in footnote 2 of the current draft of the standard, changing “on-load data” to “on-line data”

5) Reformatted sub part 2.1.1 that breaks the three alternatives for acquiring the unit MW response for model verification into 3 bullets instead of listing all three in a sentence.

Organization	Yes or No	Question 5 Comment
Southwest Transmission Cooperative, Inc.	Negative	We are assuming the question really intended to reference footnote 4. **Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question. In current draft of the standard, the partial load rejection footnote is Footnote 2.** We appreciate the examples and believe they go a long way towards highlighting the drafting team’s intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be

Organization	Yes or No	Question 5 Comment
		completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit's ten year anniversary of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the "10-year period" but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin "one year before the unit's 10-year anniversary date of the collection" of data per the Periodicity Table. **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If the unit is never running during a frequency excursion of the size listed, the GO can provide a statement to that effect in meeting the standard per a row that has been added to attachment 1.** Nothing in the table says anything about beginning monitoring Furthermore, it does not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the "clock" for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. **The GVSDT has attempted to clarify the table including incorporating your stated philosophy in only requiring that the model be verified by a certain date and is free to collect data at periodicities determined by the GO.** The example also seems to support the idea that "within one year" in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not

Organization	Yes or No	Question 5 Comment
		support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states "Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit's ten year anniversary" or to perform an "on-line speed governor reference change test or partial load rejection test". It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). **The GVSDT attempted to clarify the table. Of course the standard sets the periodicity, and the examples are not part of the standard but were provided to attempt to clarify. The GVSDT removed reference to when monitoring equipment is to be installed, as that is considered part of the "how" rather than the "what".** Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the "first frequency excursion event that meets Criteria 1". Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded "within one year of the of the applicable unit's ten year anniversary date". From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: "Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation." This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. **The GVSDT believes the Attachment 1 has been revised to correct the issues you note.**

Organization	Yes or No	Question 5 Comment
		We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team's intent could be lost to an auditor. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment in an attempt to clarify.** We are concerned that much of the "Or" language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed. **The GVSDT has attempted to clarify the attachment.** Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified**

Organization	Yes or No	Question 5 Comment
		Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator's turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. **Requirement R3 is a "peer review" type requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process received over whelming support by Industry based on their responses in prior postings.**

Organization	Yes or No	Question 5 Comment
		We are not convinced Requirement R4 is needed. The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. Without Requirement R4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the turbine/governor system. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding "useable" to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what "useable" is. We do not believe simply putting useable in quotes is enough. **The GVSDT thanks you for the comments. There is already a reference to Requirement R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD- 026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if num **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the standard applicability to provide added clarity.**

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. Please see responses above.		
Northeast Power Coordinating Council	No	The footnote regarding partial load rejection testing is footnote 4, not 5. The footnote should be removed and the language in 2.1.1 be revised. o 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **Regarding the suggested formatting of the text for Part 2.1.1, the GVSDT implemented the suggested format with some verbiage alterations and has retained the footnote regarding additional details for the partial load rejection test. The SDT believe that additional qualification details for the partial load rejection test are most appropriately conveyed in a footnote.** **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the footnote has been revised.**		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	No	BPA believes that partial load rejection is not a suitable test for validating on-line governor response. Most turbine controls, including digital, analog, and mechanical, have different sets of settings for on-line and off-line, and often isolated operations. The settings are quite different, therefore, BPA believes using off-line settings for on-line studies is incorrect. Recording under-frequency events is the preferred approach for governor response validation. BPA recommends removing partial load rejection as an acceptable approach for governor response validation.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Dominion- NERC Compliance Policy	No	Footnotes should not contain requirements. If necessary, then they should be moved into the requirements section (i.e. Footnote 4). Against giving the option of purposefully causing system disturbance (i.e. load rejection). It is unclear how this would benefit the reliability of the BES compared to the two other data collection methods available.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for		

Organization	Yes or No	Question 5 Comment
online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text. The GVSDT believes that the footnote is just a clarification regarding the potential use of a partial load rejection test and it is not a requirement. Also, it should be noted that the partial load rejection test is not meant as a system disturbance (to produce an under-frequency event to verify the models of the units that remained online). The partial load rejection is a staged test that, under certain conditions, could be applied for the verification of the turbine/speed governor model of the unit undergoing the partial load rejection.		
PPL	No	Comments: a. The referenced footnote is number 4, not 5. R2.1.1 and the verification table later in the standard allow the alternative of an on-line speed governor reference change test. In any event the standard requires that, if a naturally-occurring disturbance meeting Criterion 1 does not occur within the specified ambient-monitoring period, we must create one. We are opposed to making it mandatory that GOs conduct such testing. An on-line speed governor reference change test is not always possible. Where it is possible there is risk of creating a larger-than-desired disturbance, possibly threatening grid stability or tripping the generation unit. At the very least there would be a shock to the equipment and some loss of life. The same applies for a partial load-rejection test. It is meanwhile unclear how invasive such episodes would be. Power Technologies, in their paper “Testing Methods, An Overview,” states that five episodes may be required. These are expected to be hard trips, in which case the data gathered may be less useful than the GVSDT is expecting. Rejection to house load, followed by rapid re-synchronization, cannot be expected because need to avoid overspeed due to full-load rejections requires that the main steam stop valves be commanded closed at the same moment that a breaker-open signal is given. This is an unreasonable

Organization	Yes or No	Question 5 Comment
		burden to place on GOs, especially when there has not been any commensurate reliability benefit identified. The rationale in MOD-027-1, "to ensure modeling data is accurate," is far from compelling, nor is it explained why the accuracy of our present, OEM-generated data should not be equal-to or better than that identified via testing. **The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.** **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **The GVSDT understands that many turbine/speed governor controllers do not provide access to the speed reference setpoint and/or the ability to apply a step (or similar test signal) to the speed reference setpoint.** **On the other hand, if a test signal can be added to the speed reference setpoint, this test is quite safe and should not pose any risks to the equipment, to the stability of the grid or causing a trip of the unit being tested. For a speed governor with 5% droop, a 0.5% change in speed reference setpoint would result in (approximately) 10% change in MW power output of the unit. Thus, it is reasonably easy to calibrate the test signal being applied to avoid risks to the unit. Criteria 1 in Attachment 1 is somewhat equivalent to changes in speed reference setpoint in the order of 0.1% (Eastern Interconnection), 0.16% (Western and ERCOT Interconnections) and 0.25% in Quebec Interconnection.** **There is a documented discrepancy between the simulation models for**

Organization	Yes or No	Question 5 Comment
		turbines/speed governors and the actual (recorded) response of the different Interconnected Systems to disturbances resulting in frequency deviations. One such reference is the Special Publication "Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns," IEEE PES Special Publication 07TP180, May 2007. **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the footnote has been revised.** b. The response adjustment described in footnote 4 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide high-speed recordings of responses to grid disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is there any purpose to making GOs develop models or en masse hire consultants to do so. **The generator entity is responsible for ensuring that the turbine/speed governor model response matches the response from a recorded disturbance. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits.** **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner.** **Also, the Generator Owner can acquire the services of the TP or TO to assist in model verification, however, the Generator Owner will be responsible for model**

Organization	Yes or No	Question 5 Comment
		verification from a compliance perspective.
Response: Thank you for your comment. Please see responses above.		
Consolidated Edison Co. of NY, Inc.	No	We believe the footnote regarding partial load rejection testing is footnote 4, not 5. We recommend the footnote be removed and the language in 2.1.1 be revised.2.1.1: This requirement needs additional clarity. In one sentence, 2 on-line options and 1 off-line testing option have been proposed that compare the actual response to the model response. We recommend the following edits which provide more clarity and eliminate Footnote 4. o 2.1.1 Documentation comparing the applicable unit's model response to the recorded response by: o Model comparison to for either a frequency excursion from a system disturbance that meets Attachment 1 Criteria 1 with the unit on-line; or o Model comparison to a simulated test that varies a speed governor frequency reference within the speed control or MW control system reference change with the unit on-line; or o Model comparison to or from a partial load rejection test including an explanation as to why an off-line test is valid for the control system being modeled.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		

Organization	Yes or No	Question 5 Comment
Regarding the suggested formatting of the text for Part 2.1.1, the GVSDT implemented the suggested format with some verbiage alterations and has retained the footnote regarding additional details for the partial load rejection test. The SDT believe that additional qualification details for the partial load rejection test are most appropriately conveyed in a footnote. **There was indeed a problem with the numbering of the footnotes, which has been addressed. The text of the Footnote has been revised.**		
Independent Electricity System Operator	No	Footnote 5 as written contains requirements that are in addition to Part 2.1.1 as opposed to provide clarification or explain the testing process. We suggest that the requirements in Footnote 5 be put into Part 2.1.1 or its sub-part. We also suggest that the language be made clearer, in particular the use of the word "load" in "load rejection", "load or set point control", and "on load" which is very confusing.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.** **The GVSDT believes that the footnote is just a clarification regarding the potential use of a partial load rejection test and it is not a requirement. Note that the text of the footnote has been revised to correct a typo (on-load data changed to on-line data)**		
Public Service Enterprise Group (PSEG)	No	Footnote 4, not Footnote 5, addresses the question. Typo in Footnote 4: The word "on" should be deleted in this phrase in the last sentence: "...if the final model is not validated from on load date under..."
Response: The GVSDT thanks you for your comment. There was indeed a problem with the numbering of the footnotes, which has		

Organization	Yes or No	Question 5 Comment
been addressed. The text of the Footnote has been revised.		
Public Utility District No. 1 of Clark County	No	My Utility's only generator is a combustion turbine with a steam turbine and generator all attached to one shaft. Any load rejection event decreases the life of the components and should be avoided unless absolutely necessary. While partial load rejection testing may not significantly impact other forms of generation (i.e. hydro) the GVSDT needs to exercise caution in using simulated load rejection as a means of testing generator response.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **In the case of a single-shaft combined-cycle unit like the example described in this comment, the GVSDT believes that a partial load rejection test would not be applicable. And, as such, the verification of the models would have to rely on the other options in Part 2.1.1 (frequency excursion from a system disturbance or a speed governor speed reference step change.** **Note that the text of Footnote 5 (Footnote 2 in the current draft of the standard) has been revised to correct a typo (on-load data changed to on-line data)**		
Wisconsin Electric Power Company	No	There is not nearly enough confidence that governor testing on a unit connected to the system is safe or desirable, whether it is partial load testing or a change in the speed governor reference. Footnote 4 seems to make the value of any online testing very questionable. NERC should work with turbine-generator and controls suppliers (OEM's) to validate the concept of online testing of governor controls. The use of recorded data during frequency excursions also requires more information on what would constitute adequate data. In summary, more work on such a requirement for online testing is needed, as well as collaboration with equipment suppliers.

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text. The GVSDT understands that many turbine/speed governor controllers do not provide access to the speed reference setpoint and/or the ability to apply a step (or similar test signal) to the speed reference setpoint. On the other hand, if a test signal can be added to the speed reference setpoint, this test is quite safe and should not pose any risks to the equipment, to the stability of the grid or causing a trip of the unit being tested. For a speed governor with 5% droop, a 0.5% change in speed reference setpoint would result in (approximately) 10% change in MW power output of the unit. Thus, it is reasonably easy to calibrate the test signal being applied to avoid risks to the unit. Criteria 1 in Attachment 1 is somewhat equivalent to changes in speed reference setpoint in the order of 0.1% (Eastern Interconnection), 0.16% (Western and ERCOT Interconnections) and 0.25% in Quebec Interconnection.		
Ameren	No	We agree with the inclusion of an additional option, but find this footnote to be a concern. The footnote is too vague and provides no guidance on an appropriate model, the acceptable quantitative differences or any way for a GO to benchmark the adequacy of its verification.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.		

Organization	Yes or No	Question 5 Comment
Alberta Electric System Operator	No	The AESO does not consider a partial load rejection test to be an appropriate method of model validation for base loaded units.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Seattle City Light	No	It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed.
Response: The GVSDT thanks you for your comment. Part 2.1.1 states that the verification may be accomplished by one of the following methods: the recorded response to a system frequency excursion, an on-line governor reference change, or a partial load rejection test. **The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.** **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
American Electric Power	No	AEP is not certain that load rejection testing would be an acceptable means of verification, particularly given that a unit is disconnected from the system and the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>issues alluded to in the footnote. Is the drafting team completely confident that this is an appropriate means of verification and could not produce a mischaracterization of unit behavior during system frequency excursions?</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation.

The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.</td></tr>
<tr><td>Georgia Transmission Corporation</td><td>No</td><td>Why not model what was tested?</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The GVSDT understands that the question is related to why not model the speed governor as tested, for instance, based on a partial load rejection. With this understanding in mind, the answer is simple: because quite often the response following a partial load rejection has a different dynamic characteristic than what would be the response while in service, synchronized to the grid. Therefore, a model validated based on this different dynamic response would be incorrect to represent the expected performance of the equipment while connected to the grid.</td></tr>
<tr><td>Seattle City Light</td><td>No</td><td>It appears but is unclear if a partial load rejection test is acceptable. The unit on-line test is difficult to capture without functioning Digital Fault Recorders, which are not available at all plants. Seattle City Light requires a clarification in the text if on-line testing required or is a partial load rejection test allowed.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. Part 2.1.1 states that the verification may be accomplished by one of the following methods: the recorded response to a system frequency excursion, an on-line governor reference change, or a partial load rejection test. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
Tacoma Power	Yes	The question above should have referenced footnote 4.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question.		
ACES Power Standards Collaborators	Yes	We are assuming the question really intended to reference footnote 4.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4. The GVSDT regrets the incorrect reference in the question.		
Southern Company	Yes	The footnote number in the clean version is Footnote 4. The footnote reflects our concerns about the validity of data taken from partial load rejection testing when compared to the unit response during normal operating load levels.
Response: The GVSDT thanks you for your comment. The partial load rejection test is very useful for the verification of the turbine/speed governor model, if it can be demonstrated that the turbine controls after the load rejection are the same as for online operation. It is quite common to have automatic changes to the turbine controls when a load rejection is detected, in which case the partial load rejection test is not applicable for the verification of the turbine/speed governor model for online operation. **The GVSDT believes that the partial load rejection should not be ruled out as a possible method for the verification of turbine/speed governor models, but felt it was important to highlight the fact that the partial load rejection test might not be applicable, which is the intent of the footnote text.**		
South Carolina Electric and Gas	Yes	The footnotes in the redline and clean versions of MOD-027-1 have different numbering.

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that there must be viable options available in the event that a frequency excursion of the appropriate magnitude was not captured during the validation time frame. This may be more applicable to smaller generation facilities, or those which have a small capacity factor and are rarely online. We also agree that some further analysis may be required to account for the difference in operating conditions as described in the footnote.
Response: The GVSDT thanks you for your comment. The intent of Part 2.1.1 is to offer these alternatives and the GVSDT believes that any of these options, when applicable, would lead to the desired result: a verified model.		
Xcel Energy	Yes	The footnote that should be referenced in the question is Footnote 4. Xcel agrees that the control mode differences when using a partial load rejection must be identified.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the posted standard. The GVSDT regrets the incorrect reference in the question.		
SERC Planning Standards Subcommittee		Please check footnote numbering. Footnote 5 in the redline version is labeled footnote 4 in the clean version.
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Cowlitz County PUD		Cowlitz respectfully asks that the Standard number be referenced in multiple standard comment forms. Did you mean footnote 4? As a small GO, Cowlitz would have to hire a consultant to comment on this question, and therefore must defer to larger GO's who have the appropriate subject matter experts available.

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. Unfortunately, the question should have referenced footnote 4 in the clean version of the standard. The GVSDT regrets the incorrect reference in the question.		
Southwest Power Pool Standards Development Team	Yes	
FirstEnergy	Yes	
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Luminant Power	Yes	

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	
Los Angeles Department of Water and Power	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Exelon	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
American Wind Energy Association	Yes	
Kansas City Power & Light	Yes	
SERC Generation Subcommittee		No comment
SERC Dynamic Review Subcommittee (DRS)		No comment

Organization	Yes or No	Question 5 Comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.
Indiana Municipal Power Agency		No comment

6. **The GVSDT has provided guidance on the periodicity aspects of Attachment 1. Do you agree? If not, please explain in the comment area below.**

Summary Consideration: Stakeholders were evenly divided in their opinions regarding the periodicity aspects of Attachment 1. The GVSDT received suggestions for improvements which include the following:

1) Numerous revisions were made to clarify the language in Attachment 1.

2) Row numbers were added to Attachment 1.

3) The following text was removed from R2: "within 365 calendar days from the date that the response was recorded".

4) In Attachment 1, the column title "Comments" was changed to "Required Action".

5) The 25/50/75/100% phase in allowing GOs to install MW Recorders was removed from the standard. This phase in unnecessarily complicated the Implementation Plan considering the vast majority of units already have recorders or processes in place where MW response can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that low resolution data, approximately one sample per second, is adequate for turbine/governor and load control or active power/frequency control function model verification.

Organization	Yes or No	Question 6 Comment
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the motivation and purpose for the 10 year recurring validation period is not clearly defined. BC Hydro recommends either supplying better supporting justification, or consideration should be given to modify this criteria, ie remove the blanket 10 year requirement. In place of the blanket interval, alternative criteria recommended are a) for machines equipped with digital excitation and governor control, no recurring testing required because there is nothing that can change (software doesn't drift), b) for machines with either or both non-digital exciter and governor control, recurring testing should be required every X years (analog control is more susceptible to setting drift and other issues) BC Hydro supports the remaining reasons for requiring validation.

Organization	Yes or No	Question 6 Comment
Response: The GVSDT thanks you for your comment. The SDT believes that the 10 year periodicity is appropriate and has received industry support for this concept, specifically as a result of the first posting. Digital excitation systems settings can be modified, and there are other components in the closed loop system that can degrade with heat and stress over time (SCRs, discrete electronic components, hydraulic components, etc). **In the specific case of turbine/speed governor controls, there are many mechanical or hydraulic components that could degrade over time, despite having a digital controller. Thus, the GVSDT considers that periodic re-validation is necessary.**		
Consumers Energy	Negative	The generator model with the excitation system and the load rejection testing or frequency step response testing is difficult to perform and has possibilities of damaging equipment and causing reliability issues on the system in order to perform.
Response: The GVSDT thanks you for your comment. MOD-027 is written to allow for the use of ambient monitoring, recorded data associated with the normal operation of your equipment. A GO with your concerns can alleviate the issues you mention using ambient monitoring.		
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard MOD-027-1. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. The testing required in the proposed standard is onerous and quite expensive for small GO. In April 2009, we tested our 2 generating units and submitted to WECC the results of the generator validation results and subsequently received a certificate of compliance. Since we recently completed model certification, is the next date 10 years from completion or 2019? **You are correct, the standard is written to allow you to use the prior test for the initial period if it complies with the requirements. Please see the Attachment 1 "Consideration for Early Compliance". The GVSDT has attempted to improve the clarity of Attachment 1.** The MOD-027 Attachment 1 is unclear in this regard. I believe the model testing can be spread out even further than 10 years, especially for the smaller units (less than 100MVA) and plants, say every 20 years. Most of the parameters collected do not

Organization	Yes or No	Question 6 Comment
		change and are related to the construction of the generation unit. Standard unit models for hydro are close enough without the testing. Making small plants go through this exercise is overkill. Maybe WECC should have a standard model test group and take care of this testing for small plants. **The standard drafting team considered what the periodicity should be and decided that 10 years is appropriate (and it is actually a longer period than currently required by WECC). It is important that there be periodic model validation. Even if no equipment changes are made, a review of the model may point out errors that have crept into the model over time. The standard does also recognize plant size and does not require model verification for plants smaller than the given size for the interconnection. The model verification needs to be the responsibility of entities that have physical access to the equipment although they may bring others in to assist.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
SERC Dynamic Review Subcommittee (DRS)	No	Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? The DRS recommends that this be reviewed for consistency.
Response: The GVSDT thanks you for your comment. The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The SDT has corrected the inadvertent use of the last “and” by changing it to an “or” (Turbine/governor and load control or active power/frequency control).		
Tacoma Power	No	Attachment 1, especially the column titled “Verification Periodicity” is difficult to interpret. For example, for the “Event Triggering Verification” row titled “Initial verification for a new applicable unit...” the periodicity is stated as “Record unit Real Power response to first frequency excursion.... OR record unit Real Power response for....reference change....no more than 365 calendar days from the commissioning date”. This language implies that there is no stated periodicity applied if the

Organization	Yes or No	Question 6 Comment
		generator owner elects the frequency excursion event option. Rather the generator owner must interpret that such an event has occurred, even if it happens 15 years later, and then has 365 calendar days to verify the model. The periodicity as applied to existing fleet and new/changed fleet should be made easier to interpret.
Response: The GVSDT thanks you for your comment. The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.		
Florida Municipal Power Agency	No	The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **Your interpretation is correct, however, since each interconnection has several events a year that meet the frequency deviation threshold for verification, it is**

Organization	Yes or No	Question 6 Comment
		unlikely that the unit would not be running for all of them. On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? **If there is no event when the equipment is available, the GO can submit a statement to that effect. A row was added to Attachment 1 to provide for that circumstance.** We recommend numbering the rows in the table so that row references are clear. **The GVSDT has added row numbers.**
City of Vero	No	The "OR" statements are ambiguous in the table of Attachment 1: - On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** - On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **Your interpretation is correct, however, since each interconnection has several**

Organization	Yes or No	Question 6 Comment
		events a year that meet the frequency deviation threshold for verification, it is unlikely that the unit would not be running for all of them. - On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? - Etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? **If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.** We recommend numbering the rows in the table so that row references are clear. **The GVSDT has added row numbers.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
PPL	No	We must wait for naturally-occurring disturbances, if not creating upsets of our own, making it impossible to guarantee up-front that the 25%-3 yrs, 50% - 5 yrs etc requirements will be met. Such requirements also conflict with the instruction in the periodicity table to, “Record unit Real Power response to the first frequency excursion event that meets Criteria 1 on or after the Standard Implementation Effective Date.” **You are correct, and the GVSDT added a row to the table to account for the circumstance where no event occurs while the generator is in service.** The row in the same table for, “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period, and neither an on-line speed governor reference test nor a partial load rejection test was performed,” meanwhile appears to pertain to circumstances that are not permitted by this standard. **The SDT recognizes that the table is hard to understand and has attempted to**

Organization	Yes or No	Question 6 Comment
		reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If there is no event when the equipment is running, the GO can submit a statement to that effect. A row was added to the table to provide for that circumstance.
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Power Standards Collaborators	No	We appreciate the examples and believe they go a long way towards highlighting the drafting team's intent. However, we do not believe the examples are consistent with the requirements. We agree the examples are how the requirements should be implemented but we simply believe they have not documented the requirements in a way that is consistent with the examples. The first example does not seem to be completely consistent with the standard and also contradicts itself. For instance, the language in Row 2 of the table in Attachment 1 states that the subsequent verification must occur within one year of the applicable unit's ten year anniversary of the previous collection date. This could be interpreted meaning it must occur between year 9 and 11. However, the example states (in the sixth sentence) that it must occur after the "10-year period" but then later on (in the eighth sentence) states that monitoring must begin for suitable events must begin "one year before the unit's 10-year anniversary date of the collection" of data per the Periodicity Table. **The SDT recognizes that the table is hard to understand and has attempted to reformat to provide better clarity. The various interconnections each have several events a year that meet the threshold for verification, and if the unit is running during one of the events, a verification can be performed. If the unit is never running during a frequency excursion of the size listed, the GO can provide a statement to that effect in meeting the standard per a row that has been added to attachment 1.** Nothing in the table says anything about beginning monitoring. Furthermore, it does

Organization	Yes or No	Question 6 Comment
		not make sense to limit a Generator Owner to monitoring for events within one year data collection anniversary date. A Generator Owner should be free to collect data at more frequent periodicities. If they choose to update the model based on these periodicities, the “clock” for subsequent verifications should be reset. The standard should only require that the data is collected and model verified by the given date. **The GVSDT has attempted to clarify the table including incorporating your stated philosophy in only requiring that the model be verified by a certain date and is free to collect data at periodicities determined by the GO.** The example also seems to support the idea that “within one year” in the table is intended to be 9 to 11 years given that the subsequent data collection occurs between Years 10 and 11. We support the concept of beginning monitoring in year 9 for the second example but believe the standard language as written does not support this concept. As a result, example 2 would appear to represent a compliance violation. Row 2 in the table in attachment 1 states “Record unit Real Power response for a frequency excursion event that meets Criteria 1 within one year of the applicable unit’s ten year anniversary” or to perform an “on-line speed governor reference change test or partial load rejection test”. It does not say to begin monitoring. It is unequivocal that the subsequent test must occur within 11 years given the language. We suggest updating the table language to clarify that an entity must be begin monitoring for frequency excursion events in Year 9 but one may not be recorded until well after 10-year anniversary (including more than a year). **The GVSDT attempted to clarify the table. Of course the standard sets the periodicity, and the examples are not part of the standard but were provided to attempt to clarify. The GVSDT removed reference to when monitoring equipment is to be installed, as that is considered part of the “how” rather than the “what”.** Example 4 helps highlight the issues of the language in the standard. Row 6 requires the Generator Owner to record the “first frequency excursion event that meets Criteria 1”. Row 2 of the table requires that a frequency excursion event that meets Criteria 1 must be recorded “within one year of the of the applicable unit’s ten year

Organization	Yes or No	Question 6 Comment
		anniversary date". From row 6 and the examples, it would appear the drafting team intended this to begin monitoring within one year to record the first frequency excursion event that meets Criteria 1. We agree with this concept and suggest modifying row 2 language to: "Record unit Real Power response for first frequency excursion event that meets Criteria 1 no later than the ninth anniversary date of the collection of the recorded unit Real Power response used for current validation." This language will clarify that an event earlier than the ninth anniversary may be used and also clarify that first frequency event after the ninth anniversary must be used (if an earlier event is not voluntarily used) without limiting that the event must occur within Years 9 and 11. **The GVSDT believes the Attachment 1 has been revised to correct the issues you noted.** We also believe the examples should be added to the standard as an attachment. Otherwise, they will not be part of the standard and the drafting team's intent could be lost to an auditor. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment in an attempt to clarify.** We are concerned that much of the "Or" language in the Periodicity Table regarding waiting to observe a frequency excursion or perform an on-line speed governor reference change test or partial load rejection test could be interpreted as requiring one of these two tests if a frequency excursion is not observed within the appropriate time frame. We believe the language needs to be clarified that a Generator Owner is not required to stage a test if no frequency excursion event is observed. **The GVSDT has attempted to clarify the attachment and believes that the revisions will address your comment.**

Organization	Yes or No	Question 6 Comment
Response: The GVSDT thanks you for your comment. Please see responses above.		
Puget Sound Energy	No	This periodicity would ideally be the same as MOD 25 and MOD 26 since this testing, at least in the WECC region, is all done at the same time. **The periodicity in the current drafts of MOD-026 and MOD-027, both dynamic model verification standards, are the same in the current draft of the standard. MOD-025 is a steady state model verification and is fundamentally different and requires fundamentally different expertise.** Also it is not clear to find the ten year re-test requirement in Attachment 1, in fact it just seems inferred. If it is a ten year re-testing requirement, it should be more clearly stated in one of the requirements. **The GVSDT attempted to clarify by adjusting formatting and revising Attachment 1.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southern Company	No	a) R2 references Attachment 1 for periodicity, yet also includes a "365 day" statement. Please rely on Attachment 1 for the periodicity information and remove the parenthetical element from R2. **The GVSDT has attempted to make revisions to Requirement R2 and attachment to clarify the intent, including deleting the "365 day" statement.** b) On first glance, it is not clear that pages 14-18 all comprise Attachment 1 - please label each table. **The GVSDT has attempted to reformat the table to provide better clarity, including an "Attachment 1" header on each page of Attachment 1.** c) Please number the rows of the table so that they can be easily referred to. **The GVSDT has numbered the rows.** d) The GO is not aware of system frequency excursion events at each of their

Organization	Yes or No	Question 6 Comment
		facilities to see if a Criteria 1 has occurred. **The GVSDT anticipates that NERC will maintain a list of frequency excursion events for each interconnection that is accessible to each GO. The Generation Verification SDT is closely following and coordinating with the Frequency Response SDT. It is hoped that the Frequency Response SDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, though the Frequency Response SDT has discussed this concept and is investigating the use of a tool to help facilitate the identification of appropriate frequency excursions, the process is still evolving. As an interim step, the Generation Verification SDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine/governor and load control functions for the purpose of model verification and b) would be expected to occur 15 times a year or more. If by chance a process identifying frequency excursions that can be utilized in support of standard MOD-027-1 requirements is not developed by the Frequency Response SDT, then such a process will have to be proposed for future revision to standard MOD-027-1 by the Generation Verification SDT** e) should row 1 of the table on p 15 include "existing applicable unit"? **The GVSDT revised Attachment 1 in an attempt to provide better clarity.** h) Row 2 should be labeled "Recurring verifications" as "for an existing applicable unit" is superfluous to subsequent. **The GVSDT has attempted to improve the clarity of Attachment 1.** i) What is the time frame for the Criterion 1 frequency deviation? **The Criterion 1 frequency deviation pertains to the nadir and the GVSDT has revised the reference in Attachment 1 to improve the clarity.** j) Row 4 of the table describes what is commonly termed "sister" units - the

Organization	Yes or No	Question 6 Comment
		limitation to allow sisterhood for only those units at the same physical location should be relaxed to include all identical units for the same GO/GOP either within a Balancing Area, or alternatively, within the area of responsibility for a Reliability Coordinator. The GO should be allowed to take credit for units located within the same Balancing Area (or alternatively the Reliability Coordinator area of responsibility) if he can show that the physical location is not a factor in the comparison. **The GVSDT notes the general agreement among industry with using the proxy unit approach. The GVSDT respectfully maintains that the "same physical location" requirement is necessary since it provides a strong indication of similarity of equipment and settings (which could be verified by the same field personnel during a single site review). For example, a GO/GOP could own/operate otherwise similar equipment physically located in vastly different geographic locations with substantially different Reliability Coordinator or Transmission Operator requirements (e.g. requirement for PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** k) It is not possible to comply with the R2 25/50/75/100% in 3/5/7/9 year implementation plan and fulfill the trigger verification of Row 5 of Attachment 1 table. **The GVSDT has attempted to revise the statement of the requirement including attachment 1 to clarify that if no suitable events occur, documentation of that condition will suffice. Also, the SDT removed the 25/50/75/100% phase in proposed to allow GOs to install MW Recorders over a period of several years. This phase in unnecessarily complicated the Implementation Plan considering that the vast majority of units already have recorders or processes in place where unit MW response to frequency excursions can be recorded and provided (from plant DCS systems, recorders, SCADA data, etc). Note that for units that need to acquire recorders, slow resolution data, approximately 1 sample per second, is adequate**

Organization	Yes or No	Question 6 Comment
		for turbine/governor and load control or active power/frequency control function model verification.
Response: The GVSDT thanks you for your comment. Please see responses above.		
ExxonMobil Research and Engineering	No	A model's validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit's response.
Response: The GVSDT thanks you for your comment. The subject models need to reflect operating modes, installation of load controllers in plants, etc. Periodic model verification is needed to ensure that a model review is performed periodically to capture the effects of changing situations, in addition to the initial verification and triggered verifications. The GVSDT believes the 10 year periodicity provides for appropriate periodic model verification.		
Public Service Enterprise Group (PSEG)	No	For ease of reference, we suggest that the three examples in the Background section of the Comment form be incorporated into Attachment 1 or as a separate attachment in the standard.
Response: The GVSDT thanks you for your comment. The GVSDT has elected to omit the examples from the standard because the examples cannot capture all possible situations and may mislead. The standard needs to be clear and unambiguous.		
Manitoba Hydro	No	See comment (3) provided in Question 8.
Response: The GVSDT thanks you for your comment. The response to your question follows your comment in Question 8.		
Los Angeles Department of Water and Power	No	The criteria "Consideration for Early Compliance" seems to parallel the language for the draft of MOD-026-1 which deleted the redundant statement of, "The Generator Owner has an existing verified model that is compliant with the requirements of this

Organization	Yes or No	Question 6 Comment
		standards." It is understood that the applicable entity is compliant if it meets this criteria.
Response: The GVSDT thanks you for your comment. The GVSDT has checked the wording so that the Consideration for Early Compliance wordings is consistent between MOD-026 and MOD-027.		
Wisconsin Electric Power Company	No	When it takes five pages to describe the periodicity requirements, the standard is overly complicated.
Response: The GVSDT thanks you for your comment and has attempted to clarify and simplify the statement of the periodicity requirement in Attachment 1.		
Ameren	No	(1)We believe that any testing or verification required by MOD-012, MOD-013, MOD-026 and MOD-027 should have the same periodicity so that all required tasks can be performed in parallel. Note that earlier we have suggested a 10 year cycle. (2)We believe Attachment 1, row 4 is intended to allow "sister unit" testing so plants with multiple identical units are not required to verify each identical unit during each verification cycle. If this is the case, please clarify this option more clearly in the Attachment or the Standard.
Response: The GVSDT thanks you for your comment. MOD-012 and MOD-013 are data submittal requirements only, fundamentally different from the draft MOD-026 and 027 model verification standards – thus identical periodicities will not result in any efficiencies. We appreciate your support of the GVSDT 10 year periodicity. You are correct with regard to the "sister unit" policy. The GVSDT has attempted to revise Attachment 1 to improve clarity.		
Seattle City Light	No	Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation.
Response: The GVSDT thanks you for your comment. The GVSDT attempted to specify what had to be done, but to leave decisions about how it is done to the verification expert. The GVSDT has revised Attachment 1 in an attempt to improve clarity.		

Organization	Yes or No	Question 6 Comment
Part 2.1.1 lists three possible methods of verifying governor response, one of which is recording the unit response to a system frequency excursion while the unit is on-line.		
American Electric Power	No	The Attachment 1 table is difficult to read, and the information contained could be more clearly conveyed than it currently is. The event triggers and periodicity span across multiple pages, making it a challenge to use effectively. Titling the column “Comments” does not properly describe the information that column contains. Suggest re-naming this column as “Action Required”. **The GVSDT has revised the Comments column title accordingly.** Within the section for “Subsequent verification for an existing applicable unit”, it is unnecessary and counter-intuitive to allow the resetting of the period to only occur “within one year of the applicable unit’s ten year anniversary date...”. This should be corrected to state that the verification period could be reset for any frequency excursion occurring “or before the 10 year anniversary date”. **The standard has been revised to clarify that the 10 year period is reset whenever a verification is completed.** Within the “Event Triggering Verification” column (page 16 of the clean version), how is the following combination not non-compliant? “Existing applicable unit does not experience an acceptable frequency excursion event during the ten year unit verification period” and “Neither an on-line speed governor reference test nor a partial load rejection test was performed”. **The table has been revised in an attempt to provide additional clarity and address your comment.** Attachment 1 has references to "Not required until responsive control mode operation for connected operations is established." AEP does not understand what this statement means. **This condition applies to units that change from being unresponsive to frequency deviations to being responsive to frequency deviations. If the normal operation**

Organization	Yes or No	Question 6 Comment
		mode is changed to being frequency responsive, a verification is triggered.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Entergy Services, Inc	No	Regarding the terminology in Attachment 1, “Turbine/governor and load control and active power/frequency control”, should all the “and”s in the Event Triggering Verification column be “or”s? Entergy recommends that this be reviewed for consistency.
Response: The GVSDT thanks you for your comment. The GVSDT reviewed the “ands” and verified that they are used appropriately. The “ands” provide a limited specific condition which applies and triggers that table row. The “ands” in the phrase you quote are to be applied as explained in Footnote 1 and depend upon the equipment.		
Duke Energy	No	The Eastern Interconnection frequency excursion criteria of greater than or equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don’t provide data that is nearly as meaningful as excursions at 0.06 or 0.07.
Response: The GVSDT thanks you for your comment. The standard provides the minimum deviation to use, and certainly a larger deviation would be better if available. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.		
Georgia Transmission Corporation	No	We agree with the SERC DRS that the terminology in Attachment 1 be reviewed for consistency. Should the "and’s" be "or’s"? (“Turbine/governor and load control and active power/frequency control”)
Response: The GVSDT thanks you for your comment. The “ands” in the phrase you quote are to be applied as explained in Footnote 1 and depend upon the equipment. The GVSDT reviewed the “and”s in the table to make sure they are used		

Organization	Yes or No	Question 6 Comment
appropriately.		
Seattle City Light	No	Once every ten years seems reasonable with load rejection testing, but it is unclear if frequency excursion modeling is required during operation.
Response: The GVSDT thanks you for your comment. The GVSDT attempted to specify what had to be done, but to leave decisions about how it is done to the verification expert.		
Ingleside Cogeneration LP	Yes	We support the efforts by all project teams to clearly define the implementation and subsequent periodic evaluation time frames - as well as those that may result from changes in the facility or models. Unfortunately, any assumptions or gaps in the timelines will force NERC's Compliance team to address them through a CAN, which do not allow for sufficient vetting by the industry. In the case of MOD-027-1, we believe that the proposed intervals are sufficient to perform the frequency performance model validations; however they are initiated.
Response: The GVSDT thanks you for your supportive comment.		
Independent Electricity System Operator	Yes	We agree with the periodicity requirements. We respectfully point out once again that the periodicity criteria are not guidance, they part of Requirement R2 and must be complied with.
Response: The GVSDT thanks you for your supportive comment.		
Xcel Energy	Yes	Xcel Energy believes Attachment 1 describes more than periodicity and suggests that the first column be titled “Verification Condition” and the second column be titled “Verification Timeline” since several lines are describing how much time following an event or condition is available to complete verification (not the periodicity of the verification).
Response: The GVSDT thanks you for your comment. The GVSDT considered your comment and others and made significant		

Organization	Yes or No	Question 6 Comment
revisions in attempting to improve the clarity of Attachment 1.		
Exelon	Yes	Exelon appreciates the additional guidance provided in the Unofficial Comment Form for Project 2007-09, "Generator Verification," that includes specific examples for implementation to aid the industry in understanding the proposed model verification periodicity; however, Exelon is concerned that this information will be "lost" since it is only documented in this format. To ensure this guidance is available to registered entities in the future, Exelon suggests that this guidance, including the four examples, be added to the Implementation Plan for MOD-027-1. **The GVSDT chose not to include the examples in the standard because examples cannot capture every possible situation and may mislead, and the language in the standard needs to be clear and unambiguous. The GVSDT has reformatted the attachment 1 in an attempt to clarify.** The staggered implementation period in the current draft of MOD 027-1 and the additional guidance provided by the SDT, seems to imply, as substantiated by the examples provided above, that before the 1st model verification period at T=0 all recorders are required to be installed and ready to trigger in the case of an ambient event for each generating unit. Please clarify that the staggered implementation allows the applicable generating units to modify/install recording equipment at any time during the three year implementation period at the discretion of the Generator Owner and not that all applicable units should have the recording equipment installed and ready to trigger following regulatory approval of MOD-027-1. **We attempted to revise the Attachment 1 to provide better clarity. If the GO decides to use monitoring equipment they will need to make sure it is in place and ready to record in sufficient time to monitor ambient events. Attachment 1 was revised so that it no longer provides requirements for when monitoring equipment is installed. The test methods and details are left to the discretion of the expert. Also, a row has been added to table 1 to allow for the situation where no event is recorded that can be used for model verification – though in order to be able to**

Organization	Yes or No	Question 6 Comment
		qualify for the exemption to verify the model until the unit is subjected to a frequency event with the unit in the proper operating mode expected to govern, recorders must be in place before the effective date of the standard.
Response: The GVSDT thanks you for your comment. Please see responses above.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
Bonneville Power Administration	Yes	
Dominion- NERC Compliance Policy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	

Organization	Yes or No	Question 6 Comment
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Luminant Power	Yes	
Public Utility District No. 1 of Clark County	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
AECI	Yes	
American Wind Energy Association	Yes	
Kansas City Power & Light	Yes	
Cowlitz County PUD		Cowlitz could not find the guidance.
Indiana Municipal Power Agency		No comment

Organization	Yes or No	Question 6 Comment
SERC Generation Subcommittee		No comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.

7. **The GVSDT has address units which are always base loaded (by definition a base loaded unit is considered verified). This provides an exemption from verification for base load units. Do you agree? If not, please explain in the comment area below.**

Summary Consideration: There was a lot of industry confusion regarding the GVSDT attempt to effectively propose an exemption for base load units as the term "base load units" per say did not appear in the draft of the standard. The GVSDT inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	No	Base loaded units could provide governor response for over-frequency events and should have verified models for this event. The term "base loaded" is not defined in MOD-027.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
SERC Dynamic Review Subcommittee (DRS)	No	The DRS sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Bonneville Power	No	BPA believes that the Generator Owner needs to provide evidence that a generating

Organization	Yes or No	Question 7 Comment
Administration		unit is operated as base loaded. It will be very useful to clarify the "base loaded" terminology as operating with control valves wide open or at the temperature limit, as "base loaded" is often used for different purposes in power plants.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Tacoma Power	No	A text search of all three standards did not return the term "base loaded". Tacoma is not aware of an industry standard definition for the term "base loaded". If a unit is typically left at static output to meet base system load requirements it may likely still have droop as part of its governing system. As such, it would still be expected to respond to system frequency excursions.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Florida Municipal Power Agency	No	As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Also, if responsive control mode operation for		

Organization	Yes or No	Question 7 Comment
connected operations is established, model verification per the periodicity in Row 4 of the current draft of Attachment 1 would be required.		
PPL	No	We do not see in MOD-027-1 any language that defines baseloaded units as being verified and consequently exempts them from testing. It is true that a gas turbine running at the OEM-established baseload firing temperature is maxed-out and will therefore not exhibit any response to a frequency dip, but it is unclear what units are "always base-loaded." We also do not see any suitable definition of the term, "base loaded unit." The NERC Glossary defines "Base Load" as, "The minimum amount of electric power delivered or required over a given period at a constant rate;" but so-called baseloaded units may not run at a constant rate, instead often cycle between full output and minimum load on a daily basis.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
ACES Power Standards Collaborators	No	Conceptually, we agree with the concept of an exemption. However, it is not clear to us where this exemption is located within the standard and how it would even apply. Given the penetration of large amounts of wind and record low natural gas prices, many units that might traditionally be based load might actually operate below the maximum capabilities frequently. Our first question then, is what does it mean to be based loaded and what units qualify? Second, what does an exemption mean? Does it mean that a frequency excursion does not have to be observed or an on-line speed governor reference change test or partial load rejection test does not have to be performed? If so, does a model still have to be provided? Any exemption must be explicitly clear to avoid ambiguity and to ensure that auditors will interpret the exemption in the same manner as registered entities.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Consolidated Edison Co. of NY, Inc.	No	The term "base loaded" is not defined in MOD-027.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Luminant Energy Company LLC	No	Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and include the exemption that excludes units that are base loaded. **The GVSDT agrees that Net Capacity Factor is appropriate and has incorporated that into the standard. Please see responses to similar questions to yours in this**

Organization	Yes or No	Question 7 Comment
		document dealing with base-load units. The GVSDT thanks you for your comment. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3). **Nuclear units are not exempt from the requirements in this Standard. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Dynegy	No	We don't understand the question. The two sentences seem to contradict themselves.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Ingleside Cogeneration LP	No	Although Ingleside Cogeneration LP agrees with the concept that a base load unit does not need to be verified, it is not sufficient to capture this exception only in Attachment 1 of MOD-027-1. Similar to the exclusions for units with very low capacity factors, the Applicability section must also clearly identify that base loaded units are not subject to MOD-027-1.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. This is not an exemption, so a change in the applicability section would be inappropriate.		
Public Service Enterprise Group (PSEG)	No	We agree with exempting base load units; however, the term "base load" or "base loaded" is not referenced in the standard. We could not find the exemption or a definition of "base load" in MOD-027-1.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Luminant Power	No	Luminant agrees that base loaded units should be exempt. However, the only reference in the standard for these type exemptions are for units that have a capacity factor is 5% or less over a three year period. Luminant recommends that Net Capacity Factor (NCF) be used in the calculation and specifically include the exemption that excludes units that are base loaded in the standard. Nuclear units should be exempt from this standard and should be noted in the Facilities section (4.2.3).
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner.		

Organization	Yes or No	Question 7 Comment
Units which respond to over-frequency would need to have verification performed. **Per your and other industry comments, the SDT is specifying the use of Net Capacity Factor for the capacity factor calculation.** **Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency excursions.**		
Manitoba Hydro	No	See comment (2) in Question 8.
Response: The GVSDT thanks you for your comment. Our response will show up under Question 8.		
Wisconsin Electric Power Company	No	We agree with the concept of an exemption for units that are running most of the time. It is not at all clear where this exemption exists in the standard. Does this mean that a "base-load unit" never requires a model verification? If not, it is unclear what purpose this exemption serves.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Ameren	No	We are in agreement with the exemption in the statement, but unclear where it is provided in either the Requirements or Attachment 1. Please clarify how this option is allowed.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize		

Organization	Yes or No	Question 7 Comment
for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
ISO New England Inc.	No	Base loaded units could provide governor response for over-frequency events and should have verified models for this event.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
American Electric Power	No	We can find no mention of "base load units" in Attachment 1 or anywhere in the standard, so it is not clear that those units have indeed been exempted. There needs to be more explicit references and/or parameters with respect to the meaning of "base load units" in the body of the standard rather than an implied reference in the attachment. We don't know what the SDT believes is a "base load unit"; therefore, we cannot support an exemption.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Exelon	No	As stated in the previous comments from Exelon as documented in the Consideration of Comments on Generator Verification (MOD-027-1) - Project 2007-09 dated

Organization	Yes or No	Question 7 Comment
		2/23/12 (pp 46-47) the proposed NERC Standard MOD-027-1 should have a specific exclusion for nuclear generating units which have governors that operate to control steam pressure and which do not respond to grid frequency deviations. This is consistent with the Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group Procedure Manual version 5, May 6, 2010 which states in Appendix II, Section B Dynamic Modeling Requirements, Paragraph 2b) that "Turbine-governor representation shall be omitted for units that do not regulate frequency such as base load nuclear units, pumped storage units...". The response from the SDT on Exelon's comment was to add an additional row to Attachment 1 (the Periodicity Table) which specifies units that do not operate in control mode, except during normal start up and shut down, that would result in a turbine/governor, and load control or active power/frequency control mode response (such as valves wide open or base loaded) are not required to be verified. The SDT further stated that they believe this modification to MOD-027-1 will preclude nuclear units from having to perform model verification; and instead show compliance with the Requirement by maintaining documentation explaining the unit's operating mode. While Exelon appreciates and agrees with the addition to Attachment 1 (the Periodicity Table) as stated above, Exelon is concerned that this exclusion may not be interpreted uniformly across the Regions or by auditors and therefore suggests that the exclusion be explicit to exempt "base loaded nuclear units that do not respond to grid frequency deviations" and that the exclusion be added to the Applicability section of MOD 027-1. Note that there is no definition in the NERC Glossary of Terms of a "base loaded unit" and in a deregulated environment the term "base loaded unit" is problematic. Therefore Exelon strongly suggests that nuclear units should be explicitly excluded due to the reasons provided above. Exelon suggests addition of the following to the Applicability Section. 4.2.4 Individual base loaded nuclear generating units that do not respond to frequency deviations are exempt from the verification requirements of Standard MOD-027-11 R.2 1Base Load nuclear generating units that do not respond to grid frequency deviations are required to document circumstance for exemption in accordance with Attachment

Organization	Yes or No	Question 7 Comment
		1Exelon suggests addition of the following to the Attachment: The existing SDT proposed exclusion is as follows:"New or existing applicable unit is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)"Exelon suggests revising as follows: New or existing applicable unit is considered a Base Load nuclear generating unit that is not responsive to a frequency excursion event (The unit does not operate in a control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.)
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency excursions.		
Texas Reliability Entity	No	Only base-loaded units that are nuclear units should be exempted.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Nuclear units are not exempted, but there is a row in the Attachment 1 that accounts for units that do not respond to frequency		

Organization	Yes or No	Question 7 Comment
excursions.		
Entergy Services, Inc	No	Entergy sees no reference to base loaded units in the standard. However, we do not agree with exempting them from verification.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
City of Vero	No	As we have seen from the recent changes in fuel where gas combined cycles are dispatching before coal, the definition of what is always base loaded can change rather quickly.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed. Also, if responsive control mode operation for connected operations is established, model verification per the periodicity in Row 4 of the current draft of Attachment 1 would be required.		
Duke Energy	No	Where in this standard is this exemption for base load units? Regardless, base load units do exhibit some response, and the data collection is not difficult to accomplish.

Organization	Yes or No	Question 7 Comment
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Georgia Transmission Corporation	No	This is a MOD 25 question
Response: The GVSDT thanks you for your comment. The question was meant for MOD-027.		
Dominion- NERC Compliance Policy	Yes	Dominion agrees that base loaded units should be exempted; however, that exemption is not clearly articulated in the standard. Dominion recommends that a base load exemption statement be added to the "Applicability" section of the standard.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Southern Company	Yes	We agree that base load units should not be required to respond to demonstrate they will respond for underfrequency events and this should be reflected the transmission models.
Response: The GVSDT thanks you for your comments. We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize		

Organization	Yes or No	Question 7 Comment
for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
American Transmission Company, LLC	Yes	ATC agrees with the exception for base load units, however, recommends adding text that explicitly highlights that the second to last item in “Event Triggering Verification” column refers to base loaded units such as, “New or existing base loaded units that are normally not responsive to a frequency excursion event”.
Response: The GVSDT thanks you for your comments. We inadvertently used the term “base load” in the question on the comment form, which appears to have caused some confusion. The term “base load” is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Public Utility District No. 1 of Clark County	Yes	I agree with the concept but have been unable to find where in the proposed standard such an exemption is described. My Utility has one generator that is always operated as a baseloaded unit.
Response: The GVSDT thanks you for your comments. We inadvertently used the term “base load” in the question on the comment form, which appears to have caused some confusion. The term “base load” is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.		
Southwest Power Pool Standards Development Team	Yes	

Organization	Yes or No	Question 7 Comment
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
South Carolina Electric and Gas	Yes	
ExxonMobil Research and Engineering	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Los Angeles Department of Water and Power	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 7 Comment
AECI	Yes	
American Wind Energy Association	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
SERC Generation Subcommittee		No comment
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.
Cowlitz County PUD		Cowlitz could not find any mention of “base loaded unit” in MOD-027-1.
Indiana Municipal Power Agency		No comment

8. Do you have any other comment, not expressed in questions above, for the GV SDT regarding MOD-027-2?

Summary Consideration: Stakeholders provide many suggestions for revisions to the standard. The following revisions were made by the GVSDT:

1) A significant number of industry commenters opposed the use of the term “bulk power system” in the Applicability section. The SDT did not mean to convey a modification in the breadth of units which would be covered by the standard as “bulk power system” is a term used in the Compliance Registry. But based on the concerns expressed by industry, the SDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.
2) For clarity and ease of reading, moved a paragraph within R3 to the end of the requirement.
3) Changed “facility” to “unit” in Measures 2 and 4 to match the terminology in the requirements. Also, other minor clarifications and edits made in the Measures.
4) Changed “and” to “or” everywhere the phrase “and active power/frequency control functions” appears.
5) Revised R2 to remove “within 365 calendar days ......”
6) Revised R2.1.1 to specify “unit’s MW model response”.
7) Part 2.2 has been re-worded and merged into Part 2.1. The new verbiage makes it clear that the expert performing the model verification has flexibility regarding if the model should be represented by individual unit or plant aggregate models or any combination therein as dictated by the specific situation. This merger also results in appropriate mapping to the VSLs.
8) Revised Attachment 1 extensively for clarity, including removing specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.
9) Revised the Effective Dates, and subsequently the Implementation Plan, to mirror the Effective Dates in the current draft of MOD-026 (verification of Excitation Control Systems).
10) Removed an extra word “that” (just before the word accurately) in the Purpose statement.
11) The qualifier “directly connected” was applied at the top level of the Facilities section (A4.2) to emphasize direct connection to the BES.
12) The SDT removed the footnote regarding standby units as industry comments suggested that it did not provide additional clarity to the Applicability.
13) The SDT revised the draft standard to reference the net capacity factor calculation in Appendix F of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote in the Applicability

section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table already included the "equivalent" unit concept (Row 5)

Organization	Yes or No	Question 8 Comment
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Balancing Authority of Northern California	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Consolidated Edison Co. of New York	Affirmative	See Individual Company and NPCC group comments
Response: The GVSDT thanks you for your comment. Please refer to responses to Individual Company and NPCC group		

Organization	Yes or No	Question 8 Comment
comments.		
Pacific Gas and Electric Company	Affirmative	see WECC comments
Response: The GVSDT thanks you for your comment. Please refer to responses to WECC comments.		
Independent Electricity System Operator	Negative	1. In our previous comments, we raised a concern that Parts 5.1 to 5.3 in Requirement R5 may not be achievable despite good faith effort by the responsible entities to verify equipment model. Specifically, R5.3 stipulates that a disturbance simulation resulting in the turbine/governor and Load control or active power/frequency control model exhibiting positive damping be used to demonstrate that the model is usable. This may not be achievable, especially if such devices are new for which there are no previous simulations to benchmark with. In our previous comments, we disagreed with the condition that the simulations must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping can be affected by a number of other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to the system exhibiting positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data can be initialized without errors, or a no-disturbance simulation always results in negligible transients. We suggested the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. The SDT did not make any changes. From its response, it appears that the SDT didn't quite understand the technical basis of our concerns.

Organization	Yes or No	Question 8 Comment
		Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** 2. The change in the Applicability Section 4.2.1 from a 100kV threshold (for generators having to meet the requirements) to an MVA based threshold is a step in the right direction. However, there does not appear to be any technical justification for two of the proposed criteria, namely, 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. There is no rationale given

Organization	Yes or No	Question 8 Comment
		for assigning a 100 MVA for individual units as opposed to a 20 MVA, which is the registration criteria, and for assigning 100 MVA for plant aggregate capability as opposed to the 75 MVA that is applicable to almost all other standards on generator model verification (e.g. MOD-026), relay loadability, protection maintenance and testing, etc. Similarly, there is no rationale provided for Applicability Section 4.2.2 first bullet, and Section 4.2.3 first bullet for WECC and ERCOT, respectively. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.**
Response: Thank you for your comment. Please see responses above.		
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** b) Note 2 refers to "Applicable generating units do not include startup or standby units not normally connected to the grid." How are startup and standby units defined? **Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a startup or standby emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in isolated or islanded mode to power black start unit auxiliaries and are not configured to control grid frequency. The SDT has decided to remove this footnote as industry comments show that it has caused confusion.**
Response: Thank you for your comment. Please see responses above.		

Organization	Yes or No	Question 8 Comment
Kissimmee Utility Authority	Negative	Applicability could be simplified considerably to: o Generating Facility unit > 100 MVA gross nameplate (75 WECC, 50 ERCOT o Generating Facility plant/farm in aggregate > 100 MVA gross nameplate. (75 WECC and ERCOT) **The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** Bullet 2.2 seems to require aggregate models for plants where units are < 20 MW. Should individual models be an option, or only aggregate? **The SDT has refined section 4.2.2 of the Facilities section under Applicability to clarify the use of individual and aggregate models for plants. This clarification is also made in Part 2.1, and Part 2.2 has been deleted.** Do we have the appropriate equipment installed to measure excursions? Will we know when an excursion exceeds the frequency excursion criteria without installing equipment? **The GVSDT is closely following and coordinating with the Frequency Response Standard Drafting Team. It is hoped that the FRSDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, this is still in the conceptual phase and no processes are yet in place to identify and capture frequency excursions that meet the criteria. If a staged test is not performed, and monitoring equipment or access to SCADA data is not already in place, then each entity would have to install monitoring and recording equipment on its system in order to verify the governor responses to a system frequency excursion. It should be noted that the sampling rate required of the monitoring equipment for governor model verification is not high (one sample per 2 seconds – some entities have used even slower sampling rates) If the**

Organization	Yes or No	Question 8 Comment
		recording equipment installed included frequency threshold triggers, these triggers could be utilized to capture and identify appropriate frequency excursions, which would negate dependence on any processes defined by the FRSDT. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more. The "OR" statements are ambiguous in the table of Attachment 1: o On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the Criteria 1 threshold. Is that the correct interpretation? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line. Finally, the model representing the new equipment cannot be verified until the new equipment is installed. Also, this standard addresses model verification, not the submittal of preliminary design models.** o On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? ? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line**

Organization	Yes or No	Question 8 Comment
		o On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line** o etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? Recommend numbering the rows sow that the Row references are clear as to whether the heading row is included in the count. **The reference to 365 days was removed. The GVSDT revised Attachment 1 to remove specificity regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
Response: Thank you for your comment. Please see responses above.		
Beaches Energy Services	Negative	MOD-027 Applicability could be simplified considerably to: Generating Facility unit > 100 MVA gross nameplate (75 WECC, 50 ERCOT Generating Facility plant/farm in aggregate > 100 MVA gross nameplate. (75 WECC and ERCOT) **Thank you for your comment. The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** Bullet 2.2 seems to require aggregate models for plants where units are < 20 MW.

Organization	Yes or No	Question 8 Comment
		Should individual models be an option, or only aggregate? **Thanks you for your comment. The SDT has refined section 4.2.2 of the Facilities section under Applicability to clarify the use of individual and aggregate models for plants. This clarification is also made in Part 2.1, and Part 2.2 has been deleted.** Do we have the appropriate equipment installed to measure excursions? Will we know when an excursion exceeds the frequency excursion criteria without installing equipment? **The GVSDT is closely following and coordinating with the Frequency Response Standard Drafting Team. It is hoped that the FRSDT will create a process where frequency excursions meeting certain criteria for each Interconnection are captured. However, this is still in the conceptual phase and no processes are yet in place to identify and capture frequency excursions that meet the criteria. If a staged test is not performed, and monitoring equipment or access to SCADA data is not already in place, then each entity would have to install monitoring and recording equipment on its system in order to verify the governor responses to a system frequency excursion. It should be noted that the sampling rate required of the monitoring equipment for governor model verification is not high (one sample per 2 seconds – some entities have used even slower sampling rates) If the recording equipment installed included frequency threshold triggers, these triggers could be utilized to capture and identify appropriate frequency excursions, which would negate dependence on any processes defined by the FRSDT. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.** The "OR" statements are ambiguous in the table of Attachment 1: On initial verification of new units or new turbine / governor and load control (3rd non-heading row of table), with the "or" statement, it seems that new equipment can be installed and not verified until after the first frequency excursion that exceeds the

Organization	Yes or No	Question 8 Comment
		Criteria 1 threshold. Is that the correct interpretation? On an existing applicable unit for which an on-line speed governor reference test or partial load rejection test was not performed (5th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? On an existing applicable unit with a submitted verification plan (6th non-heading row of table), it seems that we can wait for the next frequency excursion that exceeds the frequency threshold, is that a correct interpretation? etc. Was this the intent, or was the intent to apply the "no more than 365 days ..." to both parts of the "OR" statement? Recommend numbering the rows sow that the Row references are clear as to whether the heading row is included in the count. **You are correct. The GVSDT revised Attachment 1 to provide better clarity. Accordingly, Attachment 1 no longer includes details regarding when monitoring equipment must be installed. A row was added to the table to account for the possibility that no frequency excursions meeting the criteria occur when the unit is on-line – however, in order for that row to be applicable, monitoring equipment must be in place by the effective date of the standard.**
Response: Thank you for your comment. Please see responses above.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same
Response: Thank you for your comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: Thank you. Please see response to comments of the MRO NSRF and ACES Power Marketing		

Organization	Yes or No	Question 8 Comment
Old Dominion Electric Coop.	Negative	I am sure that not all GOs will be able to supply the mode data requested in teh format requested by the TP since some units are old and this data does not exist for them. Add an exemption process for those generators that cannot provide their data.
Response: The GVSDT thanks you for your comment. Generic models exist that should adequately model any governor type. Once verification is completed and the data applied to the generic model, the model should be useful for system planning. Therefore, the GVSDT does not believe that an exemption should be granted solely due to lack of documentation.		
Pacific Gas and Electric Company	Negative	MOD-027-1 paragraph 4.2.2 of applicability section is unclear. This paragraph and sub-bullets seem to have the intent to clarify which generating units must be modeled. However, The second bullet includes generating plant or facility consisting of one or more units connected to the bulk power system at a common bus with total generation greater than 75 MVA. The sub-bullets then define individual generating unit greater than 20 MVA and generating plant or facility comprised of individual generating units less than 20 MVA. At face value it would seem to include both units greater than 20 MVA and less than 20 MVA. If the intent is to include individual models for units greater than 20 MVA and an aggregate model for the sum of all units less that 20 MVA, that should be clearly identified. However, it does leave the reader wondering what to do with units that are exactly 20 MVA.
Response: Thank you for your comment. Based on your comment, the SDT has refined section 4.2.2 of the standard applicability to add additional clarity.		
JEA	Negative	MOD027-1: Believe that requiring verification for facilities with a capacity factor of only 5% is too stringent. Provide some type of justification for this value or increase. A unit with only a 5% capacity factor will usually not be part of the BES if an event

Organization	Yes or No	Question 8 Comment
		occurs and so we need to balance the cost verses the probability of impact.
Thank you for your comment. The SDT believes it is not necessary to require all units in the compliance registry to have models unit capacity factor of 5% equates to greater than 400 hours of annual unit run time. The 5% capacity factor exemption was selected a balance between the cost and benefits. The SDT revised the draft standard to reference the net capacity factor calculation in f of the GADS Data Reporting Instructions. Also, the SDT moved the details of the capacity factor exemption concept form a footnote icability section to a row (Row 8) in the Periodicity Table. The team thought that would be appropriate as the Periodicity Table luded the "equivalent" unit concept (Row 5).		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
Response: The GVSDT thanks you for your comment. Please see response to MRO NSRF comments.		
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please refer to our responses under ACES Power Marketing.		

Organization	Yes or No	Question 8 Comment
Essential Power, LLC	Negative	R1 and parts of R2 are, in effect, duplicative of requirements in other Standards. The requirement for the GO should be to simply provide the specific data, in the format requested, as requested by the TP. **Requirements R1 and R2 are not duplicative requirements in other Standards. The GVSDT believes that all of the Requirements are necessary to ensure successful model verification. Requirements R1, R2, and R5 are always required, but Requirements R3 and R4 are anticipated to be rarely used for model verification activities that are not expected to occur frequently.** In regards to the facilities to which this Standard is applicable, the term 'bulk power system' used in section 4.2 is ambiguous and is not defined in the current, approved version of the NERC Glossary of Terms. The term should be changed to 'Bulk Electric System', as defined in the Glossary. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
Response: Thank you for your comments. Please see responses above.		
Lincoln Electric System	Negative	Refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Response: The GVSDT thanks you for your comment.		
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Response: The GVSDT thanks you for your comment. Please refer to our responses under ACES Power Marketing.		

Organization	Yes or No	Question 8 Comment
Luminant Energy	Negative	See comments submitted by Luminant Energy. VOTE NO based on a comparison of R2 and corresponding VSL. It is unclear how the time frames are to be aligned.
Response: The GVSDT thanks you for your comment. The requirement is for the Generator Owner to provide a verified model within certain time frames per Attachment 1. If the Generator Owner fails to meet the time requirement, the VSL will be used to determine where the violation falls within the penalty matrix. Each VSL is written such that successive VSLs are incremented by 30 days for instances of the model being provided late.		
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
Response: The GVSDT thanks you for your comment.		
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Response: The GVSDT thanks you for your comment.		
Florida Municipal Power Pool	Negative	See FMPA comments
Lakeland Electric	Negative	See FMPA comments.
Response: The GVSDT thanks you for your comment.		
Central Electric Power Cooperative	Negative	see Matt Pacobit’s comments from AECI
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit’s comments from AECI

Organization	Yes or No	Question 8 Comment
KAMO Electric Cooperative	Negative	See Matt Pacobit's comments from AECI
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI.
Sho-Me Power Electric Cooperative	Negative	See Matt Pacobit's comments from AECI.
Response: The GVSDT thanks you for your comment.		
U.S. Army Corps of Engineers	Negative	See MRO-NSRF comments.
Response: The GVSDT thanks you for your comment.		
New York Power Authority	Negative	See NPCC submitted comments
Response: The GVSDT thanks you for your comment.		
Snohomish County PUD No. 1	Negative	SNPD supports changing the WECC generator and generator unit thresholds to be consistent with the 100 MVA thresholds referenced in the Eastern and Quebec Interconnections applicability sections. **The SDT believes it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold.** SNPD also supports clarifying the language in MOD 027-1. As currently written the standards do not clearly indicate the testing that is required for plants with an

Organization	Yes or No	Question 8 Comment
		aggregate generation level greater than 75MVA and comprised of multiple units that are both greater than 20 MVA and less than 20 MVA. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** SNPD suggest changing the Bulk-Power System references to Bulk Electric System ("BES") to be consistent with most of the other NERC Reliability Standards and the title of the published Reliability Standards "Reliability Standards for the Bulk Electric Systems of North America. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility." **The intent is that at least 30% of the connected MVA must be compliant by the end of 4 years. Thus an entity with only one generator will need to complete the validation within first 4 years.** Also, the comment questionnaire indicated there is supposed to be an exemption for baseloaded generators. I cannot find such an exemption in the proposed standard. **The SDT inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that**

Organization	Yes or No	Question 8 Comment
		effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.
Response : Thank you for your comments. Please see responses above.		
Detroit Edison Company	Negative	The implementation plan is shorter than MOD-26, seems to me verifications of both these standards could be accomplished concurrently. Therefore the implementation schedules for MOD 26 & 27 should match.
Response: Thank you for your comments. The GVSDT has made the suggested modification.		
Tucson Electric Power Co.	Negative	The purpose statement appears to have an unnecessary word “that” immediately preceding the word accurately. If the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent. Do not believe that the intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both “consisting of” (4.2.1) and “comprised of” (4.2.3) and use “consisting comprised of” in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected.
Response: The GVSDT thanks you for your comment. The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.		
Tucson Electric Power Co.	Negative	The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about not providing models. If models are never provided, they are more than 90 days late. The VSLs for R5 should use “less than or equal to” rather than just “less than” in the

Organization	Yes or No	Question 8 Comment
		sections identifying how many days late the written response was provided.
Response: The GVSDT thanks you for your comment. The GVSDT agrees with your comments and has adopted them into the standard.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement in the effective date section will be a cause of confusion. Please fix it now before the standard is approved.
Response: Thank you for your comments. The GVSDT has revised this section to make it clearer. The percent values are minimum values. An entity can always choose, or may have to implement due to the fact that the number of units in their fleet is small, a higher percentage value to remain compliant.		
Sunflower Electric Power Corporation, North Carolina Electric Membership Corp.	Negative	We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. **From the VRF Guideline, a Medium Risk Requirement is:** **“A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under**

Organization	Yes or No	Question 8 Comment
		emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition." **Requirement R5 is linked directly to Requirement R2 and is a confirmation that a verified model is useable to plan the BES. If a verified model is provided by the Generator Owner, the Transmission Planner must determine whether or not the model is useable. If this step in the process is missing, then the validity and usefulness of the model is uncertain. Using uncertain models can lead to the BES being improperly planned and could "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system."** **Therefore, Requirement R5 is assigned a Medium VRF.** Additionally, conforming changes to the VSLs are required based on changes recommended to the standards in the formal comments submitted by ACES Power Marketing. **Please see response to ACES Power Marketing comments.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Southern Company	Yes	1) Applicability 4.2.1, 4.2.2, and 4.2.3 use the term "bulk power system" and should be "Bulk Electric System (BES)". We believe the >100kV criteria language should be retained. We believe the exemption for units that, by design, do not respond to frequency should be clearly stated in the Applicability section. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The units that do not respond to both under and over frequency excursions by design are compliant by informing**

Organization	Yes or No	Question 8 Comment
		the Transmission Planner. The revised periodicity table (Attachment 1) provides for that. All one has to do is submit a statement to that effect to the Transmission Planner. It is our opinion that a 20MVA machine is too small to be able to significantly impact a frequency perturbation. We believe this to be true even when it is part of a plant or Facility with an aggregate gross rating >100MVA. NERC is supposed to focus on creating standard requirements that have significant impacts on system reliability, and including units this small seems to be inconsistent with this philosophy. For plants and Facilities with an aggregate rating >100 MVA we recommend deletion of the two sub-bullets in 4.2.1, 4.2.2, and 4.2.3. In conjunction with this change, we recommend that R2, sub-part 2.2 be revised to state, "For plants or Facilities with gross aggregate rating greater than the specified thresholds in 4.2.1, 4.2.2, or 4.2.3, perform verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts.** **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 2) The Eastern Interconnection frequency excursion criteria of greater than or

Organization	Yes or No	Question 8 Comment
		equal to 0.05 should be increased to 0.06 or 0.07, or else 0.05 should be coupled with a reasonable deviation duration. Brief excursions at or just beyond 0.05 don't provide data that is nearly as meaningful as excursions at 0.06 or 0.07." **The standard provides the minimum deviation to use, and certainly a larger deviation would be better if available. The GVSDT has included minimum frequency excursion thresholds in the Periodicity Table for each Interconnection that a) are large enough to be expected to exercise turbine-governor and load control functions for the purpose of model verification, and b) would be expected to occur 15 times per year or more.** 3) Measure M2 uses the term applicable "Facilities" while R2 uses the term applicable "units". Either is acceptable to us, but the requirement and measure should use the same terminology. **The GVSDT is using the term "facility" interchangeably with "unit" in this standard. However, for clarity, the term "unit" will be used in the measure to match the requirement terminology.** 5) The purpose statement is written in a convoluted form - a more straightforward presentation could be: "To verify the models used in dynamic simulations accurately represent the generating unit real power response to system frequency variations". **The GVSDT attempted to write the purpose statement to apply to various technologies, and most of the industry found it acceptable. We considered your suggestion but did not revise the purpose statement.** 6) In Requirement R3, the paragraph above the three bullets would be more appropriate if moved below the three bullets.

Organization	Yes or No	Question 8 Comment
		Your suggestion has been incorporated. 7) Consider modifying the implementation plan to allow years for 10%, 5 years for 25%, 7 years for 50%, 9 years for 75%, and 11 years for 100% model verification due to the fact that a learning curve is involved and many entities have large numbers of units. **The applicability date requirements have been revised to match MOD-026 standard where a similar learning curve is involved.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
PacifiCorp	Yes	1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of 4.2 - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for the first bullet under section 4.2.2): "Individual generating unit greater than 75 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made throughout section 4.2 where applicable. **The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT has considered your suggestion and hopes that the use of the NERC defined term "Bulk Electric System" will make the applicability clearer. Also, the "directly connected" qualifier has been inserted at the top level of the Facilities section (A4.2).**

Organization	Yes or No	Question 8 Comment
		2. PacifiCorp believes that the sub-bullets of the second bullet under Section 4.2.2 of the "Applicability" section (and elsewhere, as applicable) introduce confusion for registered entities. If we correctly understand the intent of the GVSDT, then please consider the following language to replace the two existing sub-bullets under the second bullet of section 4.2.2: o "Each individual generating unit greater than 20 MVA (gross nameplate rating), plus an aggregate model for the other generating units of less than 20 MVA at the plant/Facility; and o Where there are no individual generating units greater than 20 MVA in a plant/Facility with total generation greater than 75 MVA (gross aggregate rating), an aggregate model for the generating units of less than 20 MVA." **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 3. PacifiCorp agrees that the addition of sub-Requirement 2.2 is a good clarification, but believe that the language could be further clarified to remove unnecessary confusion by amending the sub-Requirement as follows:"For generating plants/Facilities with total generation greater than the thresholds established in the Applicability section of this standard that are comprised of units that have gross nameplate rating of less than 20 MVA, each Generator Owner shall perform its verification using plant aggregate model(s) that include the information required by Requirement sub-parts 2.1.1 through 2.1.5." **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the expert performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ameren		(1) Footnote 4: “...validated from on load data...” For clarification, please consider that this be changed to read “...validated from on-line unit data...”.

Organization	Yes or No	Question 8 Comment
		The text has been updated and your suggestion has been taken into consideration. (2) Regarding the title of Attachment 1 “Turbine/Governor and Load Control and Active Power/Frequency Control Model Periodicity” - should the ‘and’ before ‘Active Power/Frequency Control’ be changed to an ‘or’ to be consistent with the title of the draft Standard? Similarly, the phrase “turbine/governor and load control and active power/frequency control” appears in several places in the VSL table. Should the ‘and’ before ‘active power/frequency control” be changed to ‘or’ in these instances for consistency? **The GVSDT has attempted to improve the clarity of Attachment 1. The GVSDT agrees with your comment and has revised the standard to “or active power/frequency control functions”.** (3) Violation Severity Levels - R5 Moderate: There is conflict here because failure to respond within 150 days automatically puts one in the High category. **The GVSTD agrees with your comment and has revised the standard accordingly.** (4) There is a concern that different effective dates between the MOD-26 and MOD-27 standards will be burdensome for the Transmission Planner to track and analyze model updates. The Transmission Planner would prefer to receive the exciter and governor models updates for a specific unit at the same time. **The effective date requirements have been revised to match MOD-26 standard.** (5) Replace “Bulk Power System” with “Bulk Electric System” In the Applicability section, items 4.2.1, 4.2.2, and 4.2.3. **The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.** (6) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. **The suggestion to provide technical documents on the NERC website is a good one,**

Organization	Yes or No	Question 8 Comment
		but because of copyright laws and the burden of maintaining the latest versions of the documents by NERC staff, the SDT does not believe this is feasible. (7) R2 and R2.1 require each GO to provide for each generator a "...verified turbine/governor and load control...model..." The GVSDT should provide guidance on how to quantitatively determine when a model is verified for each unit. **Based on a review of the Field Test results and experience of the SDT members, the SDT recognized that it was not desirable to develop a dynamic model verification Standard like a technical procedure manual. Such a strategy would fail as there is a wide range of equipment that will need to be verified. Thus, the SDT drafted a Standard that concentrates on "stating what is required" but without "stating how to accomplish what is required" so that the details can be managed by the modeling verification expert.**
Response: The GVSDT thanks you for the comments.		
Exelon		1) Exelon requests that the Implementation Plan for MOD-027-1, "Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions," add a section to provide guidance on the applicability of Base Loaded nuclear generating units that do not respond to frequency excursion events as explained above. In addition to the exemption criteria, more guidance should be provided on the required "document circumstance with a written statement." **Nuclear units are not exempt from the requirements in this Standard.** **We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** 2) MOD-027-1 R5 states that the Transmission Planner is to notify the Generator Owner within 90 calendar days whether the model is "useable" (i.e., meets the criteria specified in Parts 5.1 through 5.3). The usability of the model should be that

Organization	Yes or No	Question 8 Comment
		it mimics the generating unit governor regardless of whether the governor/model challenges transmission operating criteria. The requirement as written implies that a Transmission Planner could challenge the governor response to a frequency deviation (positive damping) which appears to be outside of the original purpose of Project 2007-09 (as stated in the SAR) which is "[t]o ensure that generator models accurately reflect the generator's capabilities and operating characteristics." **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance** **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to 5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** 3) Please clarify what is intended by an "applicable facility" with respect to

Organization	Yes or No	Question 8 Comment
		implementation. Is it the intent that the total population generating units that meet the characteristics in Requirements 4.2.1, 4.2.2 and 4.2.3 start as being "applicable units" for the purposes of implementation and then during the staggered implementation, each individual unit is to be evaluated for verification requirements?. For example, if a Generator Owner had ten units (five of which are nuclear units) each greater than 100 MVA and therefore all meet criteria of 4.2.1 then those ten units are in the scope of MOD-027-1 for implementation. This is regardless of any verification requirements that may then exempt them from verification per Attachment 1? **Your understanding of the applicability is correct that all units that meet the applicability threshold in sections 4.2.1, 4.2.2, and 4.2.3 are subject to model validation requirements. Also exemption guideline for applicable units is outlined in the Attachment 1.** 4) MOD-027-1 R1 is inappropriately prescriptive to Generator Owners (GOs). The Transmission Planner (TP) should merely ask for modeling parameters from a GO and not provide instructions on how to obtain acceptable models used in TP software. GOs may not own such software. **The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the model response matches the**

Organization	Yes or No	Question 8 Comment
		response from a recorded frequency excursion (or staged test allowed per Requirement R2). This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits 5) MOD-027-1 R2 is unclear as to the intended obligations. The sub-bullets in 2.1 should clearly state that following one or two of the sub-bullets are acceptable. Requiring all sub-bullets is too prescriptive and problematic. In the case of 2.1.1, fossil generating units are not likely to have the equipment necessary to demonstrate compliance. **The SDT believes that all of the applicable sub Parts in Part 2.1 are necessary to accomplish model verification. The GVSDT believes that the verification of the turbine/speed governor models can be accomplished with records containing frequency and power output, with ideal sampling rates of 1 second or faster. Some entities have verified these models using sampling rates of 4, even 6 seconds. Some plants might have such recording capability in their turbine (digital) controllers or their plant SCADA system, or obtain the data from their TOP scada system. If none of these options apply to a particular unit, a relatively inexpensive recorder with a relatively slow sampling rate (a sample every 1 – 4 seconds) to recorder the unit's MW response to frequency excursions may be required.** 6) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). **The GVSDT has taken your suggestion into account and replaced the term "bulk power system" with the NERC defined term "Bulk Electric System" without reference to registry criteria in the applicability section.**

Organization	Yes or No	Question 8 Comment
		7) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. **The GVSDT is using the NERC Standard Template which contains the language that you have concerns with. This language was provided to the drafting team for inclusion in the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Texas Reliability Entity		1)Applicability: a. Section 4.2: Section 4.2 should reference the Bulk Electric System definition for generation facilities or Transmission Planner requirements, whichever is more inclusive. At a minimum, the BES definition should be used without differences for each interconnection. The applicable Facility requirements should be the same for each Standard in this Project! **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The applicable facility requirements and effective dates are now consistent in MOD-026 and MOD-027.** b. Section 4.2: We disagree with using a capacity factor to determine which units need to comply with this Standard. The requirements should apply to all generating units, regardless of capacity factor. If the SDT decides to use the capacity factor, then the applicable facility definition needs to clearly state whether it is using the gross or net capacity per the GADS definition. **Units with less than 5% capacity factor are not likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. This standard has been revised to specify the "net capacity factor" is to be used.**

Organization	Yes or No	Question 8 Comment
		c. The SDT also needs to define how new generation units will be captured under this Standard. In our opinion, it is unacceptable to wait three years to determine if a new generation unit meets the capacity factor limit before it is determined to be an "applicable unit", then wait until a frequency excursion occurs to measure performance, then has 365 days to send the model data to the Transmission Planner. **Based upon your comments and others, we simplified Attachment 1. Now the Standard requires that the owner transmit the verified model and documentation and data to the Transmission Planner within 365 days after commissioning a new unit or making major equipment modifications.** 2)Effective Dates: a. Ten years is too long of an implementation period and should be shortened. The reliability implications of not validating responses within the models are significant. More emphasis (a shorter time frame) should be given to correct model errors that may lead to (or have led to) improper planning of the system based on the current model results. **The standard applies to each individual unit and inaccuracies in model data of an individual unit have minimum impact on the reliability. There are thousands of units involved and there will be a learning period. Based upon the overwhelming positive response, the GVSDT thinks the 10 year implementation period is a reasonable compromise.** b. For establishment of initial verification period, the MOD-027 Attachment 1 "OR" phrase is inconsistent with the timeframes to be compliant per the effective dates (e.g. If a unit records a response on the "Standard Implementation Effective Date" and then has 365 days to send the data, how can it meet the 25% compliance requirements on the first day of the first calendar quarter three years following regulatory approval?) What is the "Standard Implementation Effective Date". **The GVSDT thanks you for your comment. The standard effective date is defined in**

Organization	Yes or No	Question 8 Comment
		section 5. We have revised Attachment 1 to attempt to clarify and simplify the requirement. The periodicity no longer references how the test is completed, and accordingly the effective dates were revised to match MOD-026. c. The SDT should consider moving the Consideration for Early Compliance criteria from Attachment 1 into the Effective Dates section. **The SDT has reformatted Attachment 1 for improved clarity. The consideration for early compliance could be included in section 5, "Effective Date", but we believe the flow of the standard is best if the early compliance information appears in Attachment 1 with the other clarifying criteria.** 3) R3: The inclusion of "or a plan" extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Do the plants need to disconnect until "usable" data is provided? **The SDT drafted the standard recognizing the model verification requires expertise and calendar time – a reality that exists today in the process even in the absence of a standard. It is expected that all entities will strive to verify the model as quickly as practical. In the interim, the Transmission Planner will likely utilize a conservative model that can be run in their software or continue using the models currently available. Also, the requirements from MOD-012 still apply, so it is expected that models are available, even though they might not be considered verified models, per the requirements in this Standard.** 4) R4: The inclusion of "or plans" extends the timeframe associated with getting good modeling data. What does the Transmission Planner do in the interim? Who is responsible for the use of the data? Does the data get used at all? Ddo the plants need to disconnect until "usable" data is provided? **The SDT drafted the standard recognizing the model verification requires expertise and calendar time – a reality that exists today in the process even in the absence of a standard. It is expected that all entities will strive to verify the model as quickly**

Organization	Yes or No	Question 8 Comment
		as practical. In the interim, the Transmission Planner will likely utilize a conservative model that can be run in their software or continue using the models currently available. Also, the requirements from MOD-012 still apply, so it is expected that models are available, even though they might not be considered verified models, per the requirements in this Standard. 5) VSL R2: The Severe VSL language is different from the Lower, Moderate, and High VSL language regarding the models. Language should be consistent. **The GVSDT has removed the following text from the Requirement R2 Severe VSL section, "turbine/governor and load control and active power/frequency control", in order to provide consistency with the other R2 sections.** 6)The following comments relate to Attachment 1: a.R3: The timeframes are too long. If a GO has a unit that the TP had deemed not "usable" it has 90 days to produce a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response-then has another 365 days to send the data to the TP. What does the TP do in the interim? b.R4: The timeframes are too long. If a GO has a unit that undergoes changes to the "turbine/governor and load control and active power/frequency control system" it has 180 days to produce the model data OR a verification plan, then possibly has 365 days from the date of the verification plan submittal to record a response-then has another 365 days to send the data to the TP. More time would be needed if the TP took 90 days to verify the model data and possibly 90 more days by the GO to defend the model data, changes or verification plan (per R5 and R3). What does the TP do in the interim? c. Comment column: How do "Comments" get used in an audit? If there is a requirement to transmit information within a certain timeframe, that should be included in the "Verification Periodicity" column and not the "Comments" column. d. Criteria 4: If there are going to be references, give the references a number rather

Organization	Yes or No	Question 8 Comment
		than referring to “4th row in the following table”. **We have simplified and revised Attachment 1 in an attempt to answer comments received. This standard does not address how the TP will model the equipment in the interim until the GO meets this standard. This is a model verification standard, MOD-012 addresses the requirement to provide model data. The GO needs time to verify model data.**
Response: The GVSDT thanks you for your comments. Please see responses above.		
Indiana Municipal Power Agency		1)In section 4.2. under Facilities, IMPA recommends changing bulk power system to Bulk Electric System. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. 2)IMPA supports the use of average capacity factor in the Facilities section of the standard.
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
Alberta Electric System Operator		1. In section 4.2.2, the AESO considers the existing applicability for model validation to be more appropriate: o Connected to a transmission grid at 60 kV or higher voltage; and o single unit capacity of 10 MVA and larger; or o facilities with aggregate capacity of 20 MVA and larger. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time**

Organization	Yes or No	Question 8 Comment
		consuming verification efforts. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** 2. Requirement R2, the AESO considers the existing validation period of 5 years to be more appropriate. **The current and previous drafts of the standard have proposed a 10 year periodicity. The vast majority of comments from industry from prior posting have been in favor of a 10 year periodicity.** 3. Requirement R4, as written it appears owners of generating units that plan to change out the governor are not required to provided preliminary (design) data to the Transmission Planner only validated data. The AESO does not consider this to be appropriate as this preliminary (design) data should be provided to the Transmission Planner in advance of the change. **The standard is a model verification standard and thus does not include the provision of preliminary (design) data. However, the standard does not preclude the practice which can be implemented through contractual agreements.**
Response: Thank you for your comment. Please see responses above.		
Independent Electricity System Operator		1. In the Applicability Section, 4.2.1, we agree with the change from a 100kV threshold to an MVA based threshold. However, there does not appear to be any technical justification for the first two bullets, i.e. 100 MVA for individual units directly connected to the bulk power system and generating plant with a total of 100 MVA connecting to the bulk power system at a common bus. Why would the first bullet not be 20 MVA and the second bullet not 75 MVA to be consistent with the registration criteria and the thresholds for generators having to comply with MOD-026 and PRC-019? Similar comments on 4.2.2 first bullet, and 4.2.3 first bullet for WECC and ERCOT, respectively.

Organization	Yes or No	Question 8 Comment
		As discussed in the Comment Form with the first posting of the draft MOD-027 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the dynamic models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the turbine/speed governor models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine/speed governor models, the SDT is proposing to require verification of such models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. 2. We continue to disagree with Requirement R5 and it Parts R5.1 to R5.3 which set the criteria for usable model. The stipulated criteria may not be accomplished even if the GO provides an accurate turbine/governor and Load control or active power/frequency control model, especially if such devices are new for which there are no previous simulations to benchmark with. Part 5.3 stipulates one of the criteria for deeming a model usable. We do not agree with the condition that the simulate must exhibits positive damping. Even with an accurate turbine/governor and Load control or active power/frequency control model, system damping is affected by many other dynamic performance contributors such as other generators, system topology, power flow levels, voltage levels, excitation system and power system stabilizer settings, etc. In short, having an accurate turbine/governor and Load control or active power/frequency control model does not necessary guarantee or equate to positive damping. Similar arguments may also apply to R5.1 and R5.2, i.e., that having an accurate model does not necessarily mean that the modeling data

Organization	Yes or No	Question 8 Comment
		can be initialized without errors, and a no-disturbance simulation always results in negligible transients. We suggest the SDT to revise the determination criteria, based solely on the models specified by the TP, the data provided by the GO meeting the specified model requirements, and the tracking of actual performance, where applicable. **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance** **The models can be tested, as described in Part 5.1 to Part 5.3, based on a machine vs. infinite bus simulation model. As such, the influence of other models is removed. On the other hand, if a simulation model fails to initialize, it might indicate issues with limits and/or per unit scales and these issues should be addressed before the model can be considered approved or usable.** **The SDT wants to reiterate that model usability is a different issue than model validation. The objective here is to harmonize the validated models being provided by the Generation Owners with the actual requirements from the Transmission Planners and, ultimately, the ISO and all end-users of these models. Some regions have already established lists of approved or acceptable models.** **Requirement R5, Parts 5.1 to 5.3 are related to the usability of the models by the end-users (entities carrying out system simulations) and are not exactly related to the validity of the models. The SDT believes that the models should be not only valid models, but also usable models.** **Indeed, there is an underlying assumption that (barred some mal-function in the equipment, which would have to be addressed) all controllers in a power plant**

Organization	Yes or No	Question 8 Comment
		result in stable operation. Thus, a verified model is expected to show a similar, stable response. Therefore, it is not unreasonable to expect a stable, damped response from these simulation models. The GVSDT is not aware of any examples to the contrary.
Response: Thank you for your comment. Please see responses above.		
Wisconsin Electric Power Company		a. In Section 3 "Purpose", reference is made to Bulk Electric System (BES) reliability. Then, in Section 4.2, there are repeated references to the "bulk power system" (BPS). Please clarify the distinction, and why the standard needs to refer to both the BES and the BPS. We believe all references should be to the BES. The use of "bulk power system" could possibly lead to the inclusion of generating units in the Applicability which are not connected to the BES, and should not be subject to this standard. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** b. In Section 4.2 Applicability, Footnote 2, the reference to startup or standby units should have further detail since these terms are not defined by NERC, or simply remove this footnote. **Turbine/Governor and Load Control or Active Power/Frequency Control models are less important for a startup or standby emergency power source because these units are not typically modeled in planning studies. When needed, these units are started in isolated or islanded mode to power black start unit auxiliaries and are not configured to control grid frequency. However, based on industry comments, this footnote appears to have caused confusion thus the SDT has decided to remove it.** c. In Requirement R1, instead of the Transmission Planner (TP) providing "instructions" on how the Generator Owner (GO) can obtain necessary models and associated information, the standard should require the TP to simply "provide" the

Organization	Yes or No	Question 8 Comment
		model data and the list of acceptable models, block diagrams, etc, to the GO upon request. The TP already has the expertise with these models and the dynamics software applications, and has easy access to the necessary information. Since the Generator Owners in most cases will not have access to the dynamics software and associated libraries, it would be more efficient to have the Transmission Planner provide the information (list of acceptable models, block diagrams/data, and existing in-use model data) instead of instructing the Generator Owner how to obtain it. In addition, the TP should provide the OEM model data sheets or other data supporting the current in-use models in the dynamics database. **The software manufacturers have indicated that they will make accommodations so that generator owners without software licenses can receive the block diagrams and data sheets. Transmission planners ordinarily have license agreements that do not permit them to provide the block diagrams and data sheets directly to the generator owner.** d. In R2.1.1, the GO is required to provide documentation comparing the turbine/governor model response to the recorded response for a frequency excursion while online, or a change in reference while online, or a partial load rejection test. Since the GO usually does not have the capability to run such dynamic studies, it is not clear how will it obtain the "model response" for comparing to the recorded response. When there is more collaboration between NERC, Generator Owners and OEM's on the methods for online governor verification (see Question 5 response above), only then should there be any requirement that the GO "provide the recorded response for a frequency excursion". As presently written, R2.1.1. can only be required of the TP. Further thought and guidance needs to be given to this matter, as well as the availability and type of recording equipment needed to capture the data required in R2.1.1. This standard is too far ahead of the existing capabilities for verifying these controls. More work is needed, and it is strongly suggested to bring OEM's into the process to enable the development of a useful standard.

Organization	Yes or No	Question 8 Comment
		The SDT has assigned responsibility for model verification to the Generator Owner and has received support for this proposal from the vast majority of industry. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that model response matches the MW response from the applicable unit during an appropriate frequency excursion when the unit is in a mode in which it is expected to govern. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. Also, even though the GO would be responsible for the requirement from a compliance perspective, they could enter into an agreement with their Transmission Planner to perform a portion or all of the model verification activities. e. In Requirement R2.2, the GO is responsible to provide a verified aggregate model for multiple units rated less than 20 MVA. This will be an unreasonable burden on the GO, which typically does not have the modeling experience or the business need to develop these equivalent models like the TP does for system modeling. This requirement would demand resources in return for no increase in reliability. The requirement should allow the GO the ability to provide the same unit-specific data that is required for units rated 20 MVA or higher, or else to make the requirement applicable to both the GO and TP to allow them to work together to develop a suitable aggregate model. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section**

Organization	Yes or No	Question 8 Comment
		Applicability and Part 2.1 to provide added clarity. The new language will provide flexibility for generator owner to provide either individual or aggregate model for units rated less than 20 MVA. The standard does not preclude the Generator Owner and the Transmission Planner from working together. f. It is not clear how this standard relates to variable resources such as wind farm. It is suggested that these generating sources should be specifically excluded from the Applicability. **Some wind equipment have controls that can respond to a frequency excursion. For wind equipment that does not possess this capability, the SDT has included a row in Attachment 1 (the Periodicity Table) defining requirement exceptions for units that cannot control frequency. For these units compliance with the Requirement is shown by maintaining documentation explaining the unit's operating limitations.**
Response: Thank you for your comments. Please see responses above.		
Duke Energy		o Applicability Section 4.2 Facilities - Need to specify "net" or "gross" capacity factor for the calculation. **The standard has been revised to specify "net capacity factor" throughout.** o R2, 2.2 - Insert the phrase "or individual unit" after the word "aggregate". **The SDT moved the language that was in Part 2.2 to Part 2.1, and modified the language to make it clear that the use of individual or aggregate models for units less than 20 MVA (gross nameplate capability) is left to the discretion of the expert performing the model verification.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Pepco Holdings Inc and Affiliates		Agree with the generating unit nameplate thresholds as defined in this standard, but do not agree with eliminating the 100kV interconnection criteria from section 4.2 of

Organization	Yes or No	Question 8 Comment
		this standard and replacing it with the undefined term “bulk power system.” This subtle difference greatly expands the applicable scope of the standard from the previous draft version and would now include units that are not defined as being a part of the BES. The term “bulk power system” (BPS) is not defined within this standard, nor is it found in the NERC glossary of terms. Section 215 of the FPA defines the term “Bulk Power System” as follows: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. In effect, the statutory term “Bulk Power System” defines the jurisdiction of FERC. On November 18, 2010 FERC issued Order 743 (amended by Order 743A) and directed NERC to revise their definition of “Bulk Electric System” (ref. Project 2010-17) so that the definition encompasses all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system. As such, the applicability of this Reliability Standard should be limited to those generation facilities included in the BES definition, and not those subject to the broader BPS definition. The latest NERC BES definition includes generation resources consistent with the capacity thresholds in the Compliance Registry; however, the 100kV interconnection voltage clause in the BES definition limits the scope to those units necessary for the reliable operation of the interconnected bulk power system. In conclusion, Section 4.2 should be modified to remove the undefined term “bulk power system” and either re-instate the 100kV interconnection constraint, or reference those generation facilities as defined in the NERC BES definition.
Response: Thank you for your comments. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
Transmission Access Policy		As stated with respect to MOD-025 in TAPS response to Question 2 above, the

Organization	Yes or No	Question 8 Comment
Study Group		Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of MOD-027 be revised as follows (note that we have suggested no changes to section 4.2.3 because TAPS has not investigated the relevant conditions in ERCOT): "For the purpose of this standard, the term 'applicable Facility' is considered, 'applicable units.' Units or plants with an average capacity factor greater than 5 percent over the last three calendar years, beginning on January 1 and ending on December 31, that meet the following: 4.2.1 BES generating units/plants connected to the Eastern or Quebec Interconnections with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 100 MVA (gross nameplate rating). 4.2.2 BES generating units/plants connected to the Western Interconnection with the following characteristics: - Generating resource(s) with gross individual nameplate rating or gross plant/facility aggregate nameplate rating greater than 75 MVA (gross nameplate rating). ...A generator that is included in the BES solely by virtue of being a blackstart unit included in the Transmission Operator's restoration plan is not an applicable Facility for the purpose of this standard."
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT has made modifications to the structure of Section 4 for clarity of intent. The standard would not be applicable to most black-start units by virtue of low capacity factor.		
Consolidated Edison Co. of NY, Inc.	Yes	Comments: o Con Edison strongly supports the intent and goal of MOD-027 and the SDT efforts to achieve more accurate system modeling. o Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity

Organization	Yes or No	Question 8 Comment
		factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. **The GVSDT believes that units with less than 5% capacity factor are much less likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. The GVSDT is also aware of the fact that the very low capacity factor units will not be available for testing while operating at peak times, and it will be very expensive to test them at other times. Thus, it was necessary to establish a threshold for the applicability of the Standard.** o Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the turbine/speed governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine/speed governor models, the SDT is proposing to require verification of turbine / governor models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed.** **The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric**

Organization	Yes or No	Question 8 Comment
		System", and we believe that this is consistent with the >100 kV requirement. o Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** o Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance. We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this the SDT's understanding? **Section 5.1 has been revised to make it clearer. The intent is that the entity with one unit will need to be compliant within the first four years of standard approval date.** o R2: we believe that there is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "...unit's model response to the recorded response for either....", but this language is not clear. The SDT is encouraged to clarify what the term "response" in the parenthetical is referring to. **The text has been revised and hopefully addressed your concerns.** o R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. We recommend the following verbiage to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc) and any protection

Organization	Yes or No	Question 8 Comment
		system controls (i.e. emission control systems on combustion turbines, etc) [delete: effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or nonfunctioning governors or modes of operation that limit] the frequency response if applicable. **The SDT considers the representation of outer loop controls, particularly MW control loops, as an important element to properly represent the response of the turbine/speed governor following frequency disturbances. Thus, item 2.1.5 was included focusing specifically in this kind of component or control. The inclusion of pressure limiters and/or emission control systems in the model is left to the technical expert verifying the model.** o R3: first bullet, term "usable" should be revised to "usable as defined in Requirement 5". Note that R5.1, 5.2 and 5.3 clearly define the criteria for "usable". o Section G References: delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. **The text has been revised to indicate that usability is related to the Requirement R5.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
PPL		Comments; a. The comparison of actual and expected response in R2.1.1 should be performed by TOPs, not GOs. We provide governor model data to our TOP, they run the models, and this approach seems to work quite well. We can also provide also high-speed recordings of responses to grid-disturbances; but we do not run dynamic models or possess the software or specialty skills to do so, nor is clear that there any purpose to making GOs do so. **The SDT believes only one entity can be assigned responsible for model verification and that entity should be the Generator Owner – a concept that was affirmed by**

Organization	Yes or No	Question 8 Comment
		industry in a previous comment period. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity. The draft standard does not require the Generator entity to perform dynamic simulations to determine Bulk Electric System limits. The generator entity is responsible for ensuring that the turbine/speed governor model response matches the response from a recorded frequency excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. b. R1 should state that generation equipment OEM models are acceptable. This is the source of information we presently have for representing the dynamic response of our equipment. It is probably also the best source of data possible. **The OEM models are certainly a starting point and are more than adequate to comply with the requirements of MOD-012 and MOD-013. On the other hand, the SDT believes that verification requires a comparison of the simulation results against field measurements. Thus, the OEM models are not sufficient to comply with the requirements in this Standard, and recorded data, representative of the equipment response, is also needed.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Entergy Services, Inc		Entergy found this excerpt (section 4.2.1 bullet 2) below to be confusing, particularly the second sub-bullet below: o For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating);

Organization	Yes or No	Question 8 Comment
		and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings. Could the SDT provide some examples of how this would work? **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. **There are other standards or regional requirements, even interconnection agreements, that will determine which control modes are allowed and if the control could be changed during normal operation. This Standard aims at the verification of the response of the generation units following frequency disturbances. If the unit is switched to a control mode that renders it unresponsive to system frequency deviations, then it is still required to provide such information and associated documentation. But it should be recognized that switching to a different control mode might be a violation of other standards or requirements.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
FirstEnergy		FE offers the following comments and suggestions: 1. We are concerned that a regional or interconnection-wide excursion from the scheduled frequency may impact potentially an entity's entire generation fleet and the time frame of 365 days per R2 and Att. 1 may not be feasible. We ask the team to take this into consideration and add more time for these scenarios. **Based upon your comment, and others, we rethought the statement of periodicity and removed the requirement that verification be performed within 365 days of when the data are gathered. The revised Requirement R2 addresses when the**

Organization	Yes or No	Question 8 Comment
		model report and data are to be provided to the TP, not when the data are to be gathered, that detail is left to the GO. 2. Disturbance Monitoring Equipment (DME) necessary to obtain recorded data from excursions may be owned by the Transmission Owner and not the Generator Owner. The team may also want to consider how this MOD-027-1 standard is coordinated with the NERC PRC-002 DME standard that is still in development. **The SDT believes only one entity can be assigned responsible for model verification and that entity should be the Generator Owner – a concept that was affirmed by industry in a previous comment period. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners often work for a different company than the generation entity.** **On the other hand, cooperation with the Transmission Owner is usually a good practice. Thus, if instrumentation is available to provide the necessary recorded data for the model verification, it is certainly beneficial to have such cooperation. But it should be noted that the instrumentation needed to comply with this Standard is much simpler and probably would not qualify as a DME, under the requirements of PRC-002. If a DME is available, most likely the recorded data would be sufficient to comply with the requirements of this Standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Xcel Energy		For combined cycle steam turbines that operate with turbine control valves wide open it appears that verification is not required based on line 10 of Attachment 1. Is this a correct interpretation, or would it still need to be verified if the combustion turbine(s) supplying energy to the HRSG(s) respond to a frequency disturbance and cause the steam turbine output to respond, albeit with a very long time delay?

Organization	Yes or No	Question 8 Comment
Response: The GVSDT thanks you for your comment. In general, the combustion turbines are operated on speed governor control. Sometimes, the steady state droop settings on these combustion turbines try to compensate for the fact that the steam unit will not provide speed governor response, so the overall combined plant response meets system requirements (e.g. 4% or 5% droop). Thus, the combustion turbines would require the model verification, per the requirements of this Standard, while the steam turbine could be represented as "unresponsive" to frequency deviations. We have modified Attachment 1 to attempt to clarify that for units that do not respond to both under and over frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner.		
American Electric Power		In sections 4.2 Facilities - the voltage reference was removed and bulk power system was inserted. There is no clear voltage demarcation of bulk power system and as such this will introduce ambiguity into the standards. AEP recommends using Bulk Electric System as this is currently being defined by NERC. **The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System"** In regards to the terms "Load Control" and "Active Power/Frequency Control" used throughout, more than the clarification of footnote 1 seems necessary. Does "load control" refer to turbine and boiler coordinated control? It is our experience that variable energy plants do not regulate active power or frequency. Appropriate models may not exist at the present time for either load control or active power/frequency control. If so, what then? **The SDT considers the representation of outer loop controls, particularly MW control loops, as an important element to properly represent the response of the turbine/speed governor following frequency disturbances. Thus, item 2.1.5 was included focusing specifically in this kind of component or control. The SDT will consider the inclusion of pressure limiters and/or emission control systems, as suggested, as part of the Standard.** **We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions (such as some variable energy plants), Requirement R2 is met with a written statement to that effect transmitted to the**

Organization	Yes or No	Question 8 Comment
		Transmission Planner. **The SDT also believes that models for new technologies will eventually become available, so that is not enough justification to grant an exception to this Standard. At least the documentation of the expected response and perhaps the recorded data associated with such response can always be prepared, even when this response cannot yet be simulated.** The grammar in the Purpose section could be simplified and made more clear. **The GVSDT attempted to write the purpose statement to apply to various technologies, and most of the industry found it acceptable. We considered but did not revise the purpose statement.** Should the implementation plan for the effective date of R1 precede the effect date for R3 through R5, by 90 days perhaps? **This is not necessary. Practically speaking activities associated with Requirements R3 through R5 will occur after Requirement R1.** R 2.2: Obtaining an aggregate model would only make sense if the units comprising that aggregate are at least similar if not identical to each other. This needs to be made clear. What happens if units whose response is to be aggregated are not similar? **The SDT has refined section 4.2.2 of the Facilities section under Applicability for clarity, and moved the verbiage for the optional use of individual and aggregate models individual units rated less than 20 MVA in plants to Part 2.1.** R 2.1.2: It would be beneficial to provide examples for “Type of governor and load control and active power control/frequency control equipment” in perhaps the same manner as MOD-026-1 R2.1.2.This comment form states “The GVSDT does not believe that it is likely that the turbine/governor and Load control and active power/frequency control system will contribute to a stability limit because governor response is not consistent from one frequency excursion event to the next.” What is

Organization	Yes or No	Question 8 Comment
		meant by governor response not being consistent from one frequency excursion event to the next? Is this because of deadband or perhaps something else? **Reasons that the governor response is not consistent enough from one frequency excursion event to the next include the pre-contingency operating mode of the plant, ambient temperature, the number of coal pulverizes on line, the pre-contingency MW output of the unit, etc.** M2 - it states "... Model was verified and dated evidence of transmission, , such..." we recommend changing the sentence to be "... Model was verified and dated evidence of transmittal, such..." **The GCDST has removed the extraneous comma per your suggestion. Thank you for your comment.** VSL - requirement 5 moderate VSL needs to be changed to say "but less than or equal to 150 calendar days." Also, the "or" statement in that column needs to be changed from "181 calendar days" to "151 calendar days" **The GVSDT agrees with your first suggestion and has revised the standard accordingly. The "or" statement has been revised so there is no reference to "calendar days".**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Cowlitz County PUD		In the applicability section 4.2.2, second bullet states "comprised consisting." Cowlitz suggests deleting one of these words. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarify, including deleting the word " comprised " from the Applicability section.** Cowlitz also struggles with why the generation applicability is set at 75 MVA for the Western Interconnection. Is the SDT trying to encompass 80% of all Registered generation? Cowlitz abstains as it appears this standard may require information

Organization	Yes or No	Question 8 Comment
		that may not be possible to obtain, but can't offer technical basis at this time and will defer to commenters better equipped to answer. **The SDT is proposing to require verification of turbine / governor models associated with 80% or greater of the connected MVA per Interconnection.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: (1) - Verification of identical units - The standard should address the verification of identical sister units. There is no reason to test two identical units. **The standard is written to provide for a "sister" unit verification allowance, though the word "sister" is not used as that use of language is too "folksy" for a standard. Please see Row 5 in Attachment 1 which discusses the scenario when an Existing applicable unit that is equivalent to another unit(s) at the same physical location".** (2) - 'Base Loaded' - The drafting team should clarify what is meant by 'base loaded'. Manitoba Hydro believes that it is important to verify base loaded units. **We inadvertently used the term "base load" in the question on the comment form, which appears to have caused some confusion. The term "base load" is never used in the standard. We apologize for the confusion this has caused. We have modified Attachment 1 to attempt to clarify that for units that do not respond to frequency excursions, Requirement R2 is met with a written statement to that effect transmitted to the Transmission Planner. Units which respond to over-frequency would need to have verification performed.** (3) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied to MOD-025, MOD-027 and PRC-019.

Organization	Yes or No	Question 8 Comment
		The verification of steady state MW and Mvar capabilities (MOD-025) would be accomplished by test which is distinctly different than the activities required for verification of dynamic models. Also, the verification of steady state MW and Mvar capabilities would be accomplished without taking the unit out of service. Personnel involved in steady state MW and Mvar capabilities will almost certainly be different than personnel involved in the verification of excitation control systems (MOD-026) or turbine/speed governors (MOD-027). Also, the verification of dynamic models will almost always be ten years, whereas the periodicity of steady state MW and Mvar capabilities per the current draft of MOD-025 and the generator protection and control coordination per the current draft of PRC-019 is only five years. The current drafts of MOD-026 and MOD-027 do have identical effective dates and periodicities.
Response: The GVSDT thanks you for the comments. Please see responses above.		
Public Utility District No. 1 of Clark County		MOD-027 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 25%, 50%, and 75% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with MOD-027. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for the comments. The Effective Dates of the standard have been modified. The intent of the standard is that an entity with only one unit will comply within first four years. This is implied by the “at least” portion of the sentence.		
Seattle City Light		On-line monitoring is required to meet this draft Standard but is not yet available at all many generating plants. For the monitoring proposed, it will requires very high resolution Digital Fault Recorders that currently are not available nor required (side

Organization	Yes or No	Question 8 Comment
		note: as of right now in WECC existing generating plants below 1500 MW are not required to have DFRs, and many or most do not). The cost vs. benefit of such a demand should be reviewed and clarified.
Response **Thank you for your comment. The GVSDT believes that the verification of the turbine/speed governor models can be accomplished with records containing frequency and power output, with ideal sampling rates of 1 second or faster. Some entities have verified these models using sampling rates of 4, even 6 seconds. Some plants might have such recording capability in their turbine (digital) controllers or their plant SCADA system. For the turbine/speed governor models, the GVSDT does not believe that Digital Fault Recorders are mandatory.** **Besides, the on-line monitoring is not mandatory. Part 2.1.1 offers the options of partial load rejections (when applicable, see footnote) or speed reference setpoint step tests. Granted, there might be generation units where these two options are not feasible and, in such cases, the on-line monitoring becomes the only feasible option.**		
American Transmission Company, LLC		Please consider the following comments: 1. Applicability, 4.2.1, bullet 1 - As a Transmission Planner, ATC recommends that the unit size value be “20 MVA” rather than “100 MVA” and the aggregate plant size value be “75 MVA” rather than 100 MVA” to agree with the NERC Compliance Registry Criteria, which implies that the 20 MVA unit size and 75 MVA plant size values are large enough to be subject to the Reliability Standards. We are not aware of a definitive study that found the 100 MVA value to be appropriate for the Eastern Interconnection, particularly the upper Midwest portion of the system. **The SDT believes it is unnecessary to require all units in the compliance registry to have verified models. However, it is useful to have verified models for at least 80% of the connected MVA in the interconnection and as such the SDT has specified in the Applicability section gross nameplate rating size requirements**

Organization	Yes or No	Question 8 Comment
		for each interconnection for achieving this threshold. The SDT also believes that the applicability section thresholds specified will result in substantial accuracy improvement to the governor models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. 2. In Requirements, R1, bullet 2 -ATC recommends to change the wording to, "obtain dynamic turbine/governor, load control, and active power/frequency control model library block diagrams and/or data sheets that are acceptable to the Transmission Planner for use in dynamic simulations". Software manufacturer model library block diagrams and data sheets are usually proprietary and most Generator Owners do not own the license to receive them. Requiring instructions to simply obtain acceptable diagrams and data sheets allows the Transmission Planner to provide instructions for obtaining either public (IEEE standard) or proprietary diagrams and data sheets, depending on the Generator Owner licenses or lack of licenses. **Response: Jason** **The second bullet has been revised accordingly. Also, the major software manufacturers have agreed to provide their models as described in Requirement R1. No later than by the effective date of the standard, software manufacturers' model information can be obtained from them by entering into the agreements they require.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
Los Angeles Department of Water and Power		Provide examples for methodology and data meeting the requirement for verification using historical operational data in accordance MOD-027-1 Requirement R2; 2.1.1 for frequency excursion from a system disturbance. **Requirement R2, Part 2.1.1 simply refers to graphic plots which compare the measured and simulated responses. Model validation consists of comparing the measured and simulated response. This requirement simply asks for providing those plots.**

Organization	Yes or No	Question 8 Comment
		In regards to: 4. “Applicability” 4.2.2 Generating units connected to the Western Interconnection with the following characteristics: o Individual generating unit greater than 75 MVA. This criteria seems to conflict with the Applicability requirement of MOD-025-2; **The verification of steady state Mvar capabilities (MOD-025) is distinctly different than the activities required for verification of governor and load control functions. Also, the verification of steady state Mvar capabilities and coordination of voltage regulating system controls would be accomplished without taking the unit out of service. The verification of governor and load control functions per the current draft of MOD-27 standards will be ten years.** 4.2.1, Individual generating unit greater than 20 MVA. Why are the generating unit MVA criteria different across the MOD Standards? **The SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. This results in different MVA thresholds for different Interconnections. This philosophy has received industry support per questions asked in previous postings.**
Response: The GVSDT thanks you for the comments. Please see responses above.		
ReliabilityFirst		ReliabilityFirst abstains and offers the following comments for consideration: 1. Facilities Section 4.2a. What is the rationale/justification for the size qualification for applicable units (i.e. greater than 100 MVA)? ReliabilityFirst believes all generating units connected to the BES and referenced in the NERC Statement of Compliance Registry Criteria should be included within this standard. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the “applicability” of this proposed standard. As a basis, the SDT recognized that the turbine / governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These**

Organization	Yes or No	Question 8 Comment
		models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. **GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".** 2. Requirement R1a. For the purposes of NERC standards, "bullets points" are to be considered "OR" statements. ReliabilityFirst believes all the "bullets points" in R1 are required and should renumbered into sub-parts (i.e. 1.1, 1.2, 1.3) **The bullet points in R1 are intended to be bullets and as such, are meant to convey "or" statements. The reason is that these bullet points list information that the Transmission Planner will provide to the Generator Owner upon request from the Generator Owner.** 3. Requirement R4a. ReliabilityFirst seeks clarification on the rationale/justification for the 180 calendar day time period for the Generator Owner to provide revised model data to the Transmission Planner? ReliabilityFirst believes this data should be

Organization	Yes or No	Question 8 Comment
		provided within 90 calendar days consistent with other requirements in the standard (which require 90 calendar day submittals). **The GVSDT believes that 180 days is appropriate for Requirement R4 because it requires model data to be developed and transmitted in the event of changes made to a control system. More than 90 days may be necessary to accomplish the development verification. The requirements allowing 90 days are associated with providing instructions or readily available data (Requirement R1), written responses to comments (Requirement R3), or notification of model usefulness (Requirement R5). Also, it should be noted that an option allowed by R4 is a declaration that the GO will re-verify the model. If that is the case, Requirement R2 and Attachment 1 dictate the requirements and time lines for the subsequent model verification** 4. Proposed new Requirement R6a. ReliabilityFirst recommends the inclusion of a new Requirement R6 which would be a follow-up to Requirement R5. Requirement R5 requires the Transmission Planner to notify the Generator Owner if the model information is not useable (along with the technical description) but there is no corresponding requirement for the Generator Owner to make the model “useable” and submit it back to the Transmission Planner. ReliabilityFirst believes the feedback loop needs to be closed and a new Requirement R6 should be included. **Response:** **Requirement R5 represents established industry practice for assuring model usability. The Transmission Planner is required to notify the Generator Owner within 90 calendar days of receiving the verified model so that the Generator Owner knows if the model is useable or not. However, if the Generator Owner is notified that a model is not useable, per Requirement R3, they are only responsible for providing a written response. Thus, if the Generator Owner responds with a written response as detailed in Requirement R3, they will be in compliance.** **The GVSDT believes that these requirements (Requirement R5 for TP and Requirement R3 for GO) are sufficient to establish the proposed communication between these entities.**

Organization	Yes or No	Question 8 Comment
		5. VSLs - General format a. A number of VSLs use a parenthetical indicating the associated requirement number, some VSLs use the language “per R1”, and other VSLs do not indicate the requirement number at all. ReliabilityFirst suggest using one consistent style/format and apply to all VSLs. **The GVSDT agrees with your comment and has revised the VSLs for consistency.** b. For consistency when referencing subparts, the VSLs should have the same nomenclature. For example, the VSL for R2 states “Requirement R2, Subparts 2.1.1, through 2.1.5.” while the VSL for R5 states “Requirement R5, Parts 5.1 through 5.3.” ReliabilityFirst suggest using the following format: “Requirement R1, Part 1.X”. **The GVSDT has revised the VSLs to improve language consistency.** 6. VSL for Requirement R2 a. ReliabilityFirst recommends the language be consistent across all four sets of VSLs. For example the Lower VSL states “provided its verified model(s)” while the Severe VSL states “provided its verified turbine/governor and load control and active power/frequency control model(s).” ReliabilityFirst suggests using the language as stated in the Severe VSL for the other three VSLs. **The GVSDT has revised the VSLs for consistency.** b. There is no reference in the VSLs associated with Requirement R2, Part 2.2. ReliabilityFirst recommends adding a set of VSLs to cover a possible non-compliance with Requirement R2, Part 2.2. **The GVSDT has added the text “unit or plant aggregate” models to each Requirement R2 VSL for clarity and consistency.**
Response: The GVSDT thanks you for the comments. Please see responses above.		

Organization	Yes or No	Question 8 Comment
Tacoma Power		Requirement R2.1.5. It may be difficult to model the characteristics of outer loop controls (such as operator set point controls and load control) within the typical industry-standard modeling software parameters.
Response: The GVSDT thanks you for your comment. The outer loop control model is very important part of the model to obtain correct frequency response. Most software manufactures models include this control as an integral part of the model or a separate add on model.		
City of Vero		See response to Question 2 regarding the improper use of the term bulk power syst
Florida Municipal Power Agency		See response to Question 2 regarding the improper use of the term bulk power system
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
Tennessee Valley Authority - GO/GOP		Some consideration should be given for sister units if it can be demonstrated that the governor controls have identical settings. The 5% capacity factor threshold may be lower than necessary. Consider at least a 10% threshold since units which operate that infrequently are unlikely to be on line when a BES event occurs.
Response: Thank you. The “sister” or “proxy” unit concept is covered in Row 5 of Attachment 1 of the current draft of the standard allows consideration for an “unit that is equivalent to another unit(s)…..”		
Georgia Transmission		Some of the requirements within this standard are confusing.

Organization	Yes or No	Question 8 Comment
Corporation		
Response: The GVSDT thanks you for your comment. The current draft of the standard has been re-worked for clarity. We hope this results in a standard that is clear and unambiguous.		
Northeast Power Coordinating Council		Some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical. The intent and goal of the SDT and MOD-027 are to achieve more accurate system modeling, and are to be supported. **As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized that the turbine / governor models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the dynamic models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor models, the SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate.** Section 4.2 Facilities: there should be no capacity factor exemption for low capacity factor units. These units are likely to be operating during high load conditions, and models are typically run for peak load conditions. Therefore, even low capacity

Organization	Yes or No	Question 8 Comment
		factor units need to be accurately modeled. The 5% capacity factor limitation should be removed. **The GVSDT believes that units with less than 5% capacity factor are much less likely to be on-line during a system event, and also are difficult to test because they are operated so rarely. The GVSDT is also aware of the fact that the very low capacity factor units will not be available for testing while operating at peak times, and it will be very expensive to test them at other times.** Section 4.2.1: the Standard should apply to all BES generation greater than 20 MVA and connected at 100 kV and above. There should be no exemptions in any Region. This will yield more accurate models, which is the purpose of the Standard. **Please reference the response to the first part of your comment.** Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the term used in the Purpose of the Standard. BES is also the NERC defined term. Switching terms from the Purpose to the Applicability sections is confusing. Section 5.1 Effective Date: SDT should clarify how the staggered implementation schedule impacts GOs with less than 4 generating units. Under what schedule would a GO with one generating unit come into compliance? We assume that a GO with one generating unit would need to demonstrate compliance 9 years after regulatory approval of the Standard. Is this what is intended? **The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System". The GVSDT modified the Effective Dates of the standard to be the same as in MOD-026. The intent of the standard is that an entity with only one unit will comply within first four years. This is implied by the "at least" portion of the sentence. Similarly an entity with four units will have to test at least 30% of the MVA in first four years to comply.** R2: There is linkage between the parenthetical "(within 365 calendar days from the date that the response was recorded)" and the reference in 2.2.1 "...unit's model

Organization	Yes or No	Question 8 Comment
		response to the recorded response for either....", but this language is not clear. The term "response" in the parenthetical needs to be clarified. **The GVSDT has modified Requirement R2 Part 2.1.1 to clarify that it is the MW response of the unit and reference to 365 has been deleted.** R2.1.5: The intent of this requirement is to identify those control systems that limit load frequency response. These controls are essential to the safe operations of prime movers and protect the equipment from damage when significant power system events occur. Recommend the following wording to provide clarity: 2.1.5: Model representation of the real power response to any automatic balance of plant controls (i.e. initial pressure limiters or controllers, etc.), and any protection system controls (i.e. emission control systems on combustion turbines, etc.) effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that override the governor response (including blocked or non-functioning governors or modes of operation that limit the frequency response) if applicable. **After careful consideration and based upon the input from other industry members, the GVSDT did not feel that changing Requirement R2 Part 2.1.5 will add clarity.** R3: First bullet, term "usable" should be revised to "usable as defined in Requirement 5". Note that R5.1, 5.2 and 5.3 clearly define the criteria for "usable". **There is already a reference to Requirement R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** Section G References: Delete references as the introductory sentence says that the references contain information that is beyond the scope of the Standard. **The GVSDT believes that the references contain useful information from industry leaders regarding model verification and thus could be beneficial to many. The GVSDT does not believe that a list of relevant references will cause any confusion.**

Organization	Yes or No	Question 8 Comment
Response: The GVSDT thanks you for the comments. Please see responses above.		
Dynegy		The division of responsibility (between GO and TP) in the task of 'verifying' the model should be revisited. Some GOs have neither the modeling expertise nor the software for this task. TPs typically have more experience running these types of models. We believe a more appropriate division of responsibility is to have the GO supply the field data from the response test and let the TP run and 'verify' the models. This would also eliminate the question of what constitutes a 'verified' model, i.e., how good is good enough.
Response: The SDT considered who should be the owner of the model and asked Industry during the first posting. Generator Owners have access to the equipment, along with access to the equipment's Original Equipment Manufacturer for assistance with technical issues. Historically, the Transmission Planner and Generator Owner entities used to work for the same company, but in today's functional model environment, Transmission Planners could easily work for a different company than the generation entity. As such, the stated access advantages for the generation entity do not transfer to the Transmission Planner. For all of these reasons, the SDT believes that the Generator Owner is the appropriate entity to perform model verification activities. Finally, as the owner of the model, the peer review Requirement R3 clearly states that the Generator Owner has the final say for any technical discussions regarding the model.		
SERC Dynamic Review Subcommittee (DRS)		The DRS found the excerpt below (section 4.2.1 bullet 2)to be confusing, particularly the second sub-bullet below: o For each generating plant or generating Facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation greater than 100 MVA (gross aggregate rating): o Each individual generating unit greater than 20 MVA (gross nameplate rating); and o Each generating plant or generating Facility consisting of individual generating units less than 20 MVA (gross nameplate ratings. **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under**

Organization	Yes or No	Question 8 Comment
		Applicability to provide added clarity. Could the SDT provide some examples of how this would work? Also, if a GO disables the control mode for their unit(s), does that mean that they do not have to verify the governor model as required by this standard? Is that an incentive for all GOs to disable this feature? This would be detrimental to reliability. **Attachment 1 has been revised significantly to make it simpler and clearer. The intent is that if a unit does not have any governor control, it is important for transmission planner to know that so that its response can be modeled appropriately. How a GO operates a unit is beyond the scope of this standard.**
Response: Thank you for your comment. Please see responses above.		
Western Electricity Coordinating Council		The purpose statement appears to have an unnecessary word “that” immediately preceding the word accurately. After discussions with members of the drafting team WECC staff understands that the intent of the sub-sub-bullets in the applicability sections is intended to require that individual units greater than 20 MVA at generating plants greater than the identified Interconnection minimum be represented individually, while units less than 20 MVA at generating plants greater than the identified Interconnection minimum be represented as an equivalent, but WECC staff does not believe that intent is clearly reflected in the words in the sub-sub bullets. The sub-sub bullets in the applicability section use both “consisting of” (4.2.1) and “comprised of” (4.2.3) and use “consisting comprised of” in 4.2.2. The language should be consistent and the grammatical error in 4.2.2 should be corrected. **The SDT removed the word “that” (just before the word “accurately”) from the Purpose Statement. The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the Facilities section under Applicability to provide added clarity.** The Severe VSL for R2 includes providing required models more than 90 days late and also includes not providing models. It is not necessary to include the part about

Organization	Yes or No	Question 8 Comment
		not providing models. If models are never provided, they are more than 90 days late **The GVSDT agrees with your comment and has revised the standard accordingly.** The VSLs for R5 should use “less than or equal to” rather than just “less than” in the sections identifying how many days late the written response was provided. **The GVSDT agrees with your comment and has revised the standard accordingly.**
Response: Thank you for your comment. Please see responses above.		
Ingleside Cogeneration LP		We agree with the SDT’s position that 80% of generation capacity in each Interconnection should be targeted for validation - not the 100% that some regulatory bodies might prefer. There is a careful balance between the costs to perform the validation and the expected reliability benefit which we expect to gain. We must look for cheaper alternatives for those generators which have a negligible impact on BES performance or serve non-critical load. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of MOD-027-1, which references generation connected to the “bulk power system” rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: Thank you for your comment. The GVSDT has replaced the term “bulk power system” with the NERC defined term “Bulk Electric System”.		
ACES Power Standards Collaborators		We believe that this standard is overly administrative by memorializing the interactions between the Generator Owner and Transmission Planner that occur to model the generator’s turbine/governor and load control and active power/frequency control systems. Most of the requirements are purely

Organization	Yes or No	Question 8 Comment
		administrative and present compliance risk to the registered owners without commensurate reliability benefit. Addition of administrative requirements acts contrary to the recent efforts of FERC and NERC to eliminate compliance backlogs created by violations of requirements that present no reliability risk or benefits. The FFT process represents one such effort to eliminate these backlogs. Interestingly, within the approval order for FFT, FERC even suggested that these types of requirements need to be eliminated. Only two requirements are really needed to accomplish the purpose of this standard. They are: one requirement for the Generator Owner to perform the test and one for the Transmission Planner to verify the model is accurate. Requirement R3 highlights the overly administrative nature of the standard. Requirement R3 allows a Generator Operator to simply respond with a technical basis for leaving its model intact which does not solve the Transmission Planner's model issue. Thus, this requirement does nothing for reliability because modeling problems can be left unsolved. It should be struck. **Requirement R3 is a "peer review" type Requirement to ensure cooperation between the Generator Owner and the Transmission Planner. The SDT believes peer review is an essential part of the model verification process since the peer review provides the Transmission Planner an opportunity to review the data and identify problems or errors with information provided. The SDT believes that all entities will be equally motivated to resolve model issues. This process received over whelming support by Industry based on their responses in prior postings.** We are not convinced Requirement R4 is needed. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control that alter the equipment response characteristic. Without Requirement 4, there would be no trigger between the standard 10 year periodicity to update the model to reflect changes to the turbine / governor system.** The situation of providing model updates when changes are made to the covered control systems is already covered in Attachment 1. Since Attachment 1 is

Organization	Yes or No	Question 8 Comment
		referenced in Requirement R2, why is this additional Requirement R4 needed? If Requirement R4 is needed, we are assuming the drafting team did not think this situation was covered in Requirement R2. If this is the case, at the very least, Requirement R4 should reference Attachment 1. Otherwise, Attachment 1 would not ever apply to the situation of applicable control system changes. **Requirement R4 specifies the need for model verification due to changes to the turbine/governor and load control and active power/frequency control system that alter the equipment response characteristic. Attachment 1 addresses the required periodicity and acceptable time delays to remain compliant.** In the first bullet under Requirement R3, we suggest referencing Requirement R5 regarding "useable" to make it clear that useable is in essence defined in Requirement R5. Otherwise, the reader may not realize that Requirement R5 sets the parameters on what "useable" is. We do not believe simply putting useable in quotes is enough. **There is already a reference to R5 in the same bullet and GVSDT thinks it is not necessary to repeat it.** The numbering of the section 4.2 is not consistent with the parallel MOD-026-1 standard. MOD-026-1 uses numbers for each sub-section while this standard uses primarily bullets. It would be easier to reference and comment if numbers are used rather than bullets and would be consistent. The second bullets of Sections 4.2.1, 4.2.2, and 4.2.3 are confusing and potentially contradictory. First, these sections state that they apply to each generating plant/Facility greater than 100, 75 and 75 MVA respectively. Then, the second sub-bullet (under the second bullet) applies to generating plant/Facility. How can there be a plant within a plant? With the first sub-bullet, it appears the intent is to include generating units 20 MVA and greater within generating plants meeting the 100, 75, or 75 MVA thresholds, respectively. However, the second bullet really confuses us because it appears to bring in everything below 20 MVA which is not covered in the first bullet. These sections are further confused by the fact that they potentially apply a different threshold for

Organization	Yes or No	Question 8 Comment
		individual generating units than first main bullets which apply to individual generating units. For example, the first main bullet in section 4.2.2 applies a 75 MVA threshold to an individual generating unit and then second sub-bullet applies a 20 MVA threshold because it defines a generating plant/Facility as including one or more units. Using plant/Facility confuses the matter further. The NERC Glossary of Terms uses a generator as an example of a Facility. In the second sub-bullet, it appears the discussion is totally focused on a plant but despite the use of the singular Facility. The first main bullet under section 4.2.3 in the Facility section uses 50 MVA while the second bullet uses 75 MVA. This is not consistent with section 4.2.1 and 4.2.2 which use the same value for both bullets. Is this intentional? **The SDT has refined sections 4.2.1, 4.2.2, and 4.2.3 of the standard applicability to provide added clarity.** The purpose statement appears to have an extra "that". It begins with "that accurately represent" and is in the second to last line. **The GVSDT thanks you for your comment and made the correction.** Part 2.1 includes an ambiguous statement about using a model that is acceptable to the Transmission Planner. We assume the intent was for the Generator Owner to use a model identified by the Transmission Planner in Requirement R1. If so, we suggest changing "acceptable to the Transmission Planner" to "identified in Requirement R1". Otherwise, the Generator Owner may be compelled contact the Transmission Planner for an attestation that the model is acceptable. This further ensures that everyone (registered entity and auditors) interprets that language to mean those models identified in Requirement R1. **Requirement R2 contains the words "acceptable to Transmission Planner" since Requirement R1 may not apply in many cases. A Transmission Planner responds only if requested by GO to provide such information.** We appreciate the drafting team's consideration in Attachment 1 to allow a unit that has already verified its turbine/governor and load control and active

Organization	Yes or No	Question 8 Comment
		power/frequency control models to be considered compliant. However, it is not clear how this helps. How does the Generator Owner demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff be sufficient? Will the regional entities be willing to validate that they have confirmed regional criteria? **Using evidence from verifications prior to the standard becoming effective requires that appropriate evidence has been retained by the GO as specified in section D.1.2. Lacking such evidence, the units will be assumed to have never been validated. As always, the ultimate decision concerning compliance will be up to the RRO auditors and enforcement staff. It is suggested that this question be referred to your RRO staff following standard approval, and you can plan your validation program accordingly.** We do not believe the VRF Requirement R5 should have a Medium VRF. It is an administrative requirement that is focused on notifying the Generator Owner as to the suitability of the model they provided. **From the VRF Guideline, a Medium Risk Requirement is:** **"A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition."**

Organization	Yes or No	Question 8 Comment
		Requirement R5 is linked directly to Requirement R2 and is a confirmation that a verified model is useable to plan the BES. If a verified model is provided by the Generator Owner, the Transmission Planner must determine whether or not the model is useable. If this step in the process is missing, then the validity and usefulness of the model is uncertain. Using uncertain models can lead to the BES being improperly planned and could "under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system." **Therefore, Requirement R5 is assigned a Medium VRF.** All of the measurements use language that sounds like a requirement and is not consistent with language used in any other NERC standard. They all use "must include". It is more typical to use "shall demonstrate", "shall make available", etc. These measurements should be made consistent with other NERC standards. **The SDT believes the measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. It should be noted that this is consistent with NERC guidelines and support documentation for drafting Standards. A review of the measures did result in some corrections and clarifications.** All of the measurements use language that requires proof of transmission of the communication. Some examples of the proof include data postal receipts, dated confirmation of facsimile, etc. All evidence requirements for proof of transmission should be dropped as they go above and beyond basic evidence requirements. When is a dated and signed letter not sufficient proof? Must it also be sent by registered mail? Furthermore, any of the proofs of transmission do not prove anything other than something was transmitted. They do not prove the evidence was transmitted. For example, a confirmation report will not prove anything other than some fax was sent. Even dated and time stamped email proves only that the email was sent. It does not prove it was received. Reports on email failures are

Organization	Yes or No	Question 8 Comment
		separate reports. **The examples were offered as such: these are examples. The SDT understands that the different regions and different entities will have their specific protocols for the requirements associated with NERC Standards. As such, these methods and examples are just to illustrate the flow of information, as the SDT perceives it. These methods and examples are not part of the Requirements, but listed in the Measures. Once again, the methods listed in the Measures are for reference, but are not intended to be an exhaustive and comprehensive list of the possible ways in which this could be implemented.** The Compliance Enforcement Authority section is not the latest approved language being used by NERC. **The Compliance Enforcement Authority language was updated to reflect the latest NERC Standards template language.** We question the need to retain the "latest and previous turbine/governor and load control and active power/frequency control system model verification" as it seems excessive evidence retention. This could require Generator Owner's to retain evidence for greater than twenty years which greatly exceeds the six-year audit cycle. Thus, it would not even be reviewable in an audit per the NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. Given that the cycle for compliance exceeds the audit cycle for Generator Owners of six years, we think the drafting team should work with NERC compliance to consider how the auditing of the standard will occur. **We concur and have removed "and previous" from the Data Retention bullet pertaining to the Generator Owner for Requirement R2.** Some small entities will have audits in which no generator will have to be verified. Should this requirement even be actively monitored or should it only require proof

Organization	Yes or No	Question 8 Comment
		of compliance during investigations? **The standard is written to be size-neutral with respect to the number of units an entity may own and the size of those units. If an entity does not have any units verified during an audit period, then this would be reported for compliance.** We have identified several issues with the periodicity table in Attachment. First, the table is referred to as the periodicity table in the examples that accompany the unofficial comment form. It is not titled as such in the actual document. We believe a title would be appropriate for clarity. Second, Row 4 is not really a triggering event as the first column describes but rather a set of conditions that allow a Generator Owner to utilize an already verified unit model for a similar unit. Third, as written Row 5 only will apply when non-compliance occurs. For instance, Row 5 only applies when the 11 year period (10 year plus one year grace period) for Row 1 or Row 2 has been violated. We agree with the concept of that Row 5 presents in that a frequency event may not have occurred but the other Rows need to be clarified so that it does not present a non-compliance. Fourth, the first part of row 10 is also not really a triggering event but an exception. **We made extensive revisions to Attachment 1 to address your concerns and others.**
Response: Thank you for your comment. Please see responses above.		
ISO New England Inc.		We feel that some units under 100 MVA may have an impact on system performance and there should be a trigger for the Transmission Planner to be able to request data for certain units under 100MVA at its discretion. In some areas of the system, generator governor models have a considerable impact on dynamic performance and model accuracy is critical.
Response: As discussed in the Comment Form with the first posting of the draft MOD-026 standard, the SDT considered the extent of the facilities to be verified and how to reflect this in the "applicability" of this proposed standard. As a basis, the SDT recognized		

Organization	Yes or No	Question 8 Comment
that the turbine / governor system models and model data are already collected through the processes identified in MOD-012 and MOD-013. These models and data should, with few exceptions, already result in a quality dynamics database. However, as confirmed through the Field Test, performing the activities specified in the draft standard is expected to result in an improvement of the accuracy of the exciter models used in dynamic simulations. Utilizing engineering judgment, based in part on recent entity experiences in verifying turbine / governor system models, the SDT is proposing to require verification of dynamic models associated with 80% or greater of the connected MVA per Interconnection. Therefore, specific MVA thresholds corresponding to 80% of connected MVA or greater for each Interconnection are proposed. It is recognized that certain boundaries within an interconnection, such as BA boundaries, may have more or less than 80% of the connected MVA. The SDT further believes that a minimum unit interconnection of >100 kV, consistent with the Compliance Registry Guidelines, is appropriate. Finally, the SDT believes that the standard should apply to units with a capacity factor such that they are on-line 400 hours or greater a year. The SDT believes that these three applicability thresholds will result in substantial accuracy improvement to the turbine/governor and load control and active power/frequency control models and associated Reliability based limits determined by dynamic simulations, while not unduly mandating costly and time consuming verification efforts. Footnote 4 is intended to allow the Transmission Planner to request model information, possibly leading to model verification, for units which fall within the NERC Compliance Registry but are not of the base Applicability of this proposed standard. Also, the SDT does recognize that Regional Variances can be considered if a Region desires to include additional unit MVA in this standard.		
Kansas City Power & Light		Should replace "bulk power system" with "Bulk Electric System". Use of "bulk power system" is ambiguous where as "Bulk Electric System" is fully defined.
Response: The GVSDT thanks you for the comments. The GVSDT has replaced the term "bulk power system" with the NERC defined term "Bulk Electric System".		
Oncor Electric Delivery Company		No
SERC Generation Subcommittee		No comment

Organization	Yes or No	Question 8 Comment
Puget Sound Energy		None
Imperial Irrigation District (IID)		Abstain. Not applicable to IID.

PRC-019 Summary Consideration: Stakeholders provided feedback to make improvements to the standard and the GVSDT incorporated many of them in the standard.

A large majority of stakeholders agreed that the Applicability as drafted was correct. A significant minority of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. A number of stakeholders objected to the inclusion of synchronous condensers and black start units. The SDT did not find that valid technical arguments were presented to remove these units from the Applicability and did not make the change.

A large majority of the stakeholders agreed with the revisions made to the examples in Section G. Exelon objected that the wording in the examples implied that the Steady State Stability Limit had to be calculated based on a fixed field current. The SDT modified the wording so that the SSSL can be calculated either with fixed or variable field current. Luminant objected to the inclusion of phase distance relay characteristics on the example graphs. The SDT agreed to remove these parameters from the graphs. Dominion asked the SDT to further clarify that the coordination does not apply to all generator protective functions. The SDT revised the wording to further clarify that concept. PPL asked for an all inclusive list of limiters and protective functions to be coordinated. The SDT declined this request as stakeholders might view it as being too prescriptive.

Several stakeholders objected to the 5-year interval for verifying coordination. The SDT felt the stakeholders did not present valid reasoning for extending the interval and did not change it. Several stakeholders argued that the risk associated with non-coordination did not warrant a "High" VRF. The SDT felt the arguments were valid and revised the VRF level for both Requirements R1 and R2 to "Medium". Several stakeholders felt the VSL language did not match the requirements, or questioned the tardiness intervals. The SDT agreed that the wording in the VSL's needed revision and made the suggested changes. The SDT did not change the tardiness increments in the VSL's since they come directly from NERC guidelines. Some stakeholders objected that the Effective Date section was too restrictive for entities with a small number of units. The SDT agreed and modified the first step of implementation to extend to two years instead of one and cover 40% of the applicable units.

9. **The GVSDT applied the requirements of this standard to the functional entities Generator Owner, and Transmission Owners that own synchronous condensers rated ≥ 20 MVA. The standard applies to generating units/facilities that meet the compliance registry criteria and to synchronous condensers rated 20MVA and greater. Do you agree with this Applicability? If not, please provide an alternative and supporting information in the comment area below.**

Summary Consideration: A large majority of stakeholders agreed that the Applicability as drafted was correct. A significant minority of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. A number of stakeholders objected to the inclusion of synchronous condensers and black start units. The SDT did not find that valid technical arguments were presented to remove these units from the Applicability and did not make the change.

Organization	Yes or No	Question 9 Comment
Seminole Electric Cooperative, Inc.	Negative	a) 4.2: BPS is not a NERC defined Term in the NERC Glossary of Terms **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** b) Section C, M-1, The term "protective functions" is too broad. The specific functions should be clarified. **The SDT has added the word "applicable" before functions in Requirement R1 and Measure M1 to limit the scope to those protective functions that affect the coordination between limiters, protection and equipment capabilities.** c) Section C, M-1, Does the term "protection system" apply to the defined NERC term? **Yes, the term "Protection System" refers to the definition in the NERC Glossary of Terms.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
CPS Energy	Negative	Are variable generating units such as wind, solar, and Hyrdo included or excluded from the "applicable facility" term.
Response: The GVSDT thanks you for your comment. They are included. The standard is technology neutral.		

Organization	Yes or No	Question 9 Comment
Beaches Energy Services	Negative	PRC-019 The Applicability, Facilities section 4.2 can be deleted since this is just a repeat of the SCRC.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to clarify the applicability.		
City of Green Cove Springs, Kissimmee Utility Authority	Negative	The Applicability, Facilities section 4.2 can be deleted since this is just a repeat of the SCRC.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to clarify the applicability.		
JEA	Negative	The inclusion of a four 15 MVA units at a facility will not need to be verified and yet a single 20 MVA unit will need to be verified. Suggest making a consistent rule of 75 MVA for both single and aggregate units. Also black-start units should be removed since they are only used during emergency conditions and are already tested to verify that they can start their intended load.
Response: The GVSDT thanks you for your comment. The SDT elected to follow the NERC Registration Criteria for the applicability of PRC-019. The ability to supply dynamic reactive power and control voltage is important during system restoration and black-start units are included in this standard to assure that voltage regulating controls, limit functions, and protection systems are coordinated.		
Clark Public Utilities	Negative	The standard needs to recognize there are generator owners and transmission owners that have only a few applicable facilities and the percentage fulfillment requirement in the effective date section. Please fix it now before the standard is approved.
Response: The GVSDT thanks you for your comment. Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year. The use of "at least" in each of the Effective Date subsections recognizes generator and transmission owners with a limited number of facilities. For		

Organization	Yes or No	Question 9 Comment
example, a generation owner with only 3 facilities will need to verify two facilities by the first day of the first calendar quarter, two calendar year following approval. The third facility will need to be verified by the fourth year.		
Southern Company	No	1) Applicability, Section 4: Applicability for PRC-019 and MOD-025 should be consistent with Section 4 Applicability for MOD-026-1 and MOD-027-1 with respect to individual unit size of 100 MVA for the Eastern Interconnection. NERC is supposed to be focusing on standard requirements that have significant impacts on system reliability, and including smaller units without demonstrating their criticality to the system seems to be inconsistent with this philosophy. NERC has recognized that industry resources are limited and that we must focus on areas where reliability benefits are the greatest. We believe that if our resources are spread too thin and/or focused on areas where reliability benefits are small or questionable, that reliability will actually suffer. Verification for smaller units should be addressed on a case-by-case basis where there is a clear reliability need or justification. The individual unit size criterion should match the aggregated plant size criterion.
Response: The GVSDT thanks you for your comment. The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.		
ExxonMobil Research and Engineering	No	: A model's validity is dependent on the functionality of the installed equipment. For a properly maintained machine, if there are no changes made to the equipment, then the model should remain valid regardless of when it was last verified. While the periodicity proposed by the SDT appears reasonable, the same reliability objective can be met by requiring model verification after the initial commissioning on of a unit and at the conclusion of any equipment changes that could impact a unit's response.
Response: The GVSDT thanks you for your comment. It appears to the SDT that this comment is made in reference to MOD-027.		

Organization	Yes or No	Question 9 Comment
Please see the response provided to this same comment provided in Question 6.		
Duke Energy	No	o Comments: We disagree with linking generator applicability to the Compliance Registry criteria. Instead, the approach to applicability should be the same as that used in MOD-026-1 and MOD-027-1 (i.e. in the Eastern Interconnection, individual generating units greater than 100 MVA directly connected to the BES, etc.). Regional criteria can be used to address any smaller units identified as critical to BES reliability in that region. **The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.** o Sections 4.2.1, 4.2.2, 4.2.3 - replace “bulk power system” with “Bulk Electric System (BES)”. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Transmission Access Policy Study Group	No	As stated with respect to MOD-025 in TAPS response to Question 2 above, the Applicable Facilities should be based on the BES definition rather than on the Compliance Registry Criteria, and should be written so as not to require conforming changes if and when the BES definition changes. We therefore suggest that the Applicable Facilities section of PRC-019 be revised as follows: “For the purpose of this standard, the term, ‘applicable Facility’ shall mean ‘BES generator.’ For the purpose of this standard, a synchronous condenser is treated as a generator.”
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has		

Organization	Yes or No	Question 9 Comment
modified the standard accordingly. The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.		
Cowlitz County PUD	No	Cowlitz believes 20MVA is meant to catch users who may adversely affect the BES, such as via a faulty BES Protection System a small generator may own. The registry criteria should not endeavor to identify generation that is necessary for the support of the BES. Cowlitz feels this standard applicability conflicts with Phase 2 of Project 2010-17, Definition of Bulk Electric System. This standard should only apply to BES generation which currently is poorly defined. If this standard is needed urgently to cover a Reliability gap, Cowlitz would suggest an arbitrary 200 MVA applicability be established and a phase 2 SAR be established to adjust the standard to apply to BES generation after completion of Project 2010-17. Cowlitz commends and thanks the SDT in addressing this question.
Response: The GVSDT thanks you for your comment. The SDT agrees that the standard only applies to the BES and has changed the wording accordingly. The SDT feels that the Applicability section appropriately identified which facilities must comply with the standard.		
AECI	No	I Believe that the Ratting should be 100 MVA for all Generating units
Response: The GVSDT thanks you for your comment. The SDT feels that limiting the applicability to generating units 100 MVA and larger would fail to adequately assure reliability.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP has not changed its position that PRC-019-1 is only appropriate for generating units and facilities identified under the compliance registry criteria. Since synchronous condensers are not part of those criteria, they should be 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 - and this determination should rest with them. Similar to the strategy taken by other Standards Development Teams, the implementation plan can be modified to state that synchronous condensers will be applicable only when the updated definition of

Organization	Yes or No	Question 9 Comment
		the BES takes effect.
Response: The GVSDT thanks you for your comment. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
Pepco Holdings Inc and Affiliates	No	Same comments as in Question 2.
Public Service Enterprise Group (PSEG)	No	See comments to Question 2 above.
Florida Municipal Power Agency	No	See response to Question 2
City of Vero	No	See response to Question 2
Wisconsin Electric Power Company	No	The Applicability section in 4.2 refers to generators being connected to the "bulk power system", or BPS. The reference should be to the Bulk Electric System (BES), which is defined by NERC. The BPS is not a defined term in the NERC Glossary, and using this term is extremely confusing and possibly misleading. The GVSDT's use of the term BPS, here and in several other standards, opens the door for applying NERC standards to generating units which are connected to the system at voltages below 100 kv. The applicability should solely be to generating units of the MVA size required for registration and connected to the BES at 100 kv or higher, and to those generators which are blackstart resources.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and		

Organization	Yes or No	Question 9 Comment
protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
Tennessee Valley Authority - GO/GOP	No	The MVA criteria included in MOD-026-1 and MOD-027-1 are more appropriate for this standard than the 20 MVA criteria presently used. A 20 MVA unit is not critical enough to the BES reliability to justify this level of documentation of coordination. Standard PRC-004 already requires an investigation into relay misoperations for units greater than 20 MVA which would be the result of coordination issues.
Response: The GVSDT thanks you for your comment. The GVSDT has limited the set of applicable generators that must perform the verification activities required by MOD-026-1 and MOD-027-1 because these activities can require testing and analysis capabilities that many Generator Owners don't have on staff, and which may have to be contracted to an outside vendor. The verification activities in MOD-025-1 and engineering analysis in PRC-019-1 have been performed for many decades in some regions and typically can be easily performed by a Generator Owner's operations and engineering staff. The GVSDT does not have a technical justification for limiting the scope of these two standards.		
Northeast Power Coordinating Council	No	This Standard is applicable to generating units/facilities that meet the compliance registry criteria. However, this Standard is not applicable to any type of synchronous condensers. The purpose for synchronous condensers is to provide voltage support as needed, similar in function to a capacitor bank or shunt reactor.
Response: The GVSDT thanks you for your comment. The SDT feels that it is appropriate to include synchronous condensers because of their similarity to generators in terms of dynamic reactive power supply, voltage control, disturbance response, control functions, and protection systems. For this reason the SDT proposes to apply to the standard to similar size generators and synchronous condensers.		
ACES Power Standards Collaborators	No	We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already

Organization	Yes or No	Question 9 Comment
		requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. **The ability to supply dynamic reactive power and control voltage is important during system restoration and black-start units are included in this standard to assure that voltage regulating controls, limit functions, and protection systems are coordinated.** The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on sub-transmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: “The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system.” **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has

Organization	Yes or No	Question 9 Comment
		already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. **The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Dominion- NERC Compliance Policy	Yes	Dominion agrees, but points out that Applicability 4.2.3 as stated in the draft standard is essentially the same as NERC compliance registry criteria III.c.2; however, as worded, it could cause confusion. Dominion recommends revising 4.2.3 to match NERC compliance registry criteria III.c.2.
Response: The GVSDT thanks you for your comment. The inclusion of synchronous condensers makes it necessary to explicitly specify the full applicability.		
Ameren	Yes	The VRF and VSL need to be modified to put the significance to BES reliability in proper perspective; refer to our comments in response to question 11.
Response: The GVSDT thanks you for your comment. The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.		
Southwest Power Pool Standards Development Team	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 9 Comment
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
PPL	Yes	
Puget Sound Energy	Yes	
PacifiCorp	Yes	
Luminant Energy Company LLC	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Xcel Energy	Yes	
Luminant Power	Yes	
Manitoba Hydro	Yes	
Public Utility District No. 1 of	Yes	

Organization	Yes or No	Question 9 Comment
Clark County		
Los Angeles Department of Water and Power	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	
American Electric Power	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
Seattle City Light	Yes	
Kansas City Power & Light	Yes	
Tacoma Power	Yes	None
SERC Generation Subcommittee		No comment

Organization	Yes or No	Question 9 Comment
SERC Dynamic Review Subcommittee (DRS)		No comment
Indiana Municipal Power Agency		No comment

10. **The GVSDT revised section G based on stakeholders' comments to provide clarity and to indicate that the items listed are examples of coordination and that entities may provide "Equivalent tables or other evidence." Do you agree with the revisions to Section G? If not, please explain in the comment area below.**

Summary Consideration: A large majority of the stakeholders agreed with the revisions made to the examples in Section G. Exelon objected that the wording in the examples implied that the Steady State Stability Limit had to be calculated based on a fixed field current. The SDT modified the wording so that the SSSL can be calculated either with fixed or variable field current. Luminant objected to the inclusion of phase distance relay characteristics on the example graphs. The SDT agreed to remove these parameters from the graphs. Dominion asked the SDT to further clarify that the coordination does not apply to all generator protective functions. The SDT revised the wording to further clarify that concept. PPL asked for an all inclusive list of limiters and protective functions to be coordinated. The SDT declined this request.

Organization	Yes or No	Question 10 Comment
Exelon	No	Exelon does not believe the SDT adequately addressed the concern previously raised by Exelon regarding Section G as documented in the Consideration of Comments on Generator Verification (PRC-019-1) - Project 2007-09 dated 2/22/12 (p 18). The SDT needs to evaluate the requirements related to the Steady State Stability Limit (SSSL). Specifically, Section G (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 response given by the SDT was that "[t]he SDT agrees that the generators must normally operate in AVR mode." This does not address the conflict identified. The SDT needs to allow for automatic mode for AVR to accommodate those generating units that have redundant automatic channels as is the case for newer digital AVRs. This will allow the Generator Owner to use AVRs automatic mode when plotting SSSL. The response given by the SDT was that "[t]he 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

Organization	Yes or No	Question 10 Comment
		coordination purposes without making calculations overly complex..."Exelon does not believe this response is acceptable. PRC-019-1 should not force a Generator Owner to use the SSSL curve with the AVR in "manual". There should be an option that allows a Generator Owner to use the SSSL curve with the AVR in "manual" or in "auto." If the Generator Owner wants to use a more complex calculation to plot SSSL curve with the AVR in "auto" (which although more complex would also be more accurate) it should be left to the discretion of the Generator Owner.
Response: The GVSDT thanks you for your comment. The use of the SSSL curve in the example found in Section G is based on a conservative method of determining minimum excitation limiter settings that will result in maintaining stability of the unit in the event of a trip of the AVR from auto to manual while in steady state operation. The wording used in the example of Section G has been modified to allow an entity to calculate the SSSL curve with the excitation control system in auto, if they choose.		
Luminant Energy Company LLC, Luminant Power	No	Luminant disagrees with the need to illustrate coordination of the phase distance relay with AVR controls. The sample R-X diagram does not indicate how the relay is coordinated with field forcing capability. Since this function is covered in the generator loadability standard currently under development, Luminant recommends that this function be removed from the R-X diagram.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment and has removed the impedance relay from the attachment example. Also, the example attachments have been simplified and enhanced.		
Dominion- NERC Compliance Policy	No	Section G provides additional clarity. However, the Purpose, R1.1 and Section G do no fully align. It should be made clear that all generator protection system devices aren't applicable.
Response: The GVSDT thanks you for your comment. R1.1 identifies the scope to be the following "…the voltage regulating system controls, (including In-service 2 limiters and protection functions) with the applicable Facility capabilities and Protection System settings….". The intention of Section G is to provide some examples of evidence that will support a claim that the		

[2] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Organization	Yes or No	Question 10 Comment
elements itemized in R1.1 are coordinated. Each of the elements appearing on the examples of Section G are either parts of the voltage regulating system controls, the Facility capabilities, or the generator Protection System. The wording "settings of the applicable Protection System devices as referenced in Section G" has been added to provide limits on the scope of the verification of settings covered in this standard.		
PPL	No	The draft standard is technically sound, but additional clarity may be needed to enforce it in a uniform and unambiguous fashion. The GVSDT should list in section G all relays and associated excitation system and voltage regulator functions that, if present and active, are covered by this standard.
Response: The GVSDT thanks you for your comment. The scope of the limiters and protection elements included in the draft standard are those elements that are in-service at each entities facility where mis-coordination could result in a unit tripping before limiting, excessively damaging equipment due to continually operating beyond equipment capabilities before tripping the unit. In each of these cases, the system reliability is unnecessarily reduced. If the limiter and protection elements are not in-service, then they are not applicable.		
Kansas City Power & Light	No	This assumes that the auditor will have the protection skills and knowledge necessary to confirm that "other evidence" is equivalent to the plots shown in the attachment one examples.
Response: The GVSDT thanks you for your comment. You are correct; this burden is the responsibility of the Regional Compliance Monitoring and Enforcement entities.		
Wisconsin Electric Power Company	Yes	It is not clear how the field current limiters or trip settings are plotted on the P-Q diagram, since these parameters are dc field amps.
Response: The GVSDT thanks you for your comment. Characteristics of limiters or protection that operate on field amps can be shown on a P-Q diagram through the use of supplied generator data (i.e. V-curves, etc.). There are published technical papers on this subject, such as "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. The SDT has added some of these references to Section		

Organization	Yes or No	Question 10 Comment
F of the standard.		
Manitoba Hydro	Yes	Manitoba Hydro suggests that example curves be provided for variable generation plants.
Response: The GVSDT thanks you for your comment. The SDT believes the examples provided are adequate for representation. The GO's of VER equipment could use VER specific technical data and/or graphs as evidence for M1.		
American Electric Power	Yes	On the P-Q diagram, it is not clear how the instantaneous field current and instantaneous field current trip shown in the diagram would be relevant to coordination. These two values are not typically provided in such a diagram.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment, the instantaneous field current limit and instantaneous field current trip are not necessary to show coordination. Attachment 1has been changed to remove these characteristics. However, a GO entity may have these functions activated and could plot them on a common graph.		
Ingleside Cogeneration LP	Yes	We agree that it is appropriate to add a statement to the P-Q and R-X diagrams that they show performance at nominal voltage and frequency levels. We also agree that the SSSL calculation should be based upon a fixed field current value, even if it does not take into account the action of the AVR in automatic mode. It is a far less complex method to use and returns a more conservative value in any case. Ingleside Cogeneration would like to commend the SDT's for holding to its position that there is no need to complicate the analysis by assessing performance under transient conditions or single contingency scenarios. In our view, there is no justification to adding time and effort to an initiative until data shows that it will result in a tangible reliability benefit.
Response: The GVSDT thanks you for your comment.		
ACES Power Standards Collaborators	Yes	We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team.

Organization	Yes or No	Question 10 Comment
Response: The GVSDT thanks you for your comment.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Standards Development Team	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
Imperial Irrigation District (IID)	Yes	
FirstEnergy	Yes	
Puget Sound Energy	Yes	
Tennessee Valley Authority - GO/GOP	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Dynegy	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 10 Comment
ExxonMobil Research and Engineering	Yes	
American Transmission Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group (PSEG)	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Clark County	Yes	
Los Angeles Department of Water and Power	Yes	
Ameren	Yes	
ISO New England Inc.	Yes	
Oncor Electric Delivery Company	Yes	
TransAlta Centralia Generation LLC	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 10 Comment
Cowlitz County PUD	Yes	
Texas Reliability Entity	Yes	
Entergy Services, Inc	Yes	
AECI	Yes	
Duke Energy	Yes	
Seattle City Light	Yes	
Tacoma Power	Yes	None
SERC Generation Subcommittee		No comment
SERC Dynamic Review Subcommittee (DRS)		No comment
Indiana Municipal Power Agency		No comment

11. Do you have any other comment, not expressed in questions above, for the GVSDT regarding PRC-019-1?

Summary Consideration: A significant number of stakeholders felt that the use of the term "bulk power system" was inappropriate and should be changed to "Bulk Electric System". The SDT agreed and made that change. Several stakeholders objected to the 5-year interval for verifying coordination. The SDT felt the stakeholders did not present valid reasoning for extending the interval and did not change it. Several stakeholders argued that the risk associated with non-coordination did not warrant a "High" VRF. The SDT felt the arguments were valid and revised the VRF level for both Requirements R1 and R2 to "Medium". Several stakeholders felt the VSL language did not match the requirements, or questioned the tardiness intervals. The SDT agreed that the wording in the VSL's needed revision and made the suggested changes. The SDT did not change the tardiness increments in the VSL's since they come directly from NERC guidelines. Some stakeholders objected that the Effective Date section was too restrictive for entities with a small number of units. The SDT agreed and modified the first step of implementation to extend to two years instead of one and cover 40% of the applicable units.

Organization	Yes or No	Question 11 Comment
Indiana Municipal Power Agency	Abstain	IMPA is not voting negative on this standard, but we do believe that this standard adds additional expense and administrative burden on many smaller entities without any significant increase to the Bulk Electric System. In addition, we do not see the benefit of performing this analysis every five years if nothing has changed with the equipment (the equipment has not been changed or replaced).
Response: The GVSDT thanks you for your comment. The SDT believes there is a reliability benefit to having protection, limiters, and equipment capabilities properly coordinated. There is no need to recalculate all of the numbers every five years if the entity verifies that the settings and capabilities have not changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system		

Organization	Yes or No	Question 11 Comment
characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of 'bulk power system' to 'Bulk Electric System' would be changed on certain pertinent standards. This appears to be such a case.
Response: The GVSDT thanks you for your comment. The SDT has replaced the term "bulk power system" with "Bulk Electric System".		
Consolidated Edison Co. of New York	Affirmative	See Individual Company and NPCC group comments
BC Hydro and Power Authority	Negative	BC Hydro is voting Negative as the basis for the 5 year recurring requirements of R2 are not clear. BC Hydro recommends either providing more detailed supporting justification or taking a more balanced approach ie conduct the review upon identification or implementation of systems, equipment or setting changes that are expected to affect this coordination.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Northern Indiana Public Service Co.	Negative	Confusion since the Bulk Power System (BPS) and Bulk Electric System (BES) are both mentioned within these standards; they are not the same

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Great River Energy	Negative	Great River Energy agrees with the comments of the MRO NSRF and ACES Power Marketing.
Response: The GVSDT thanks you for your comment. Please see the SDT responses to the MRO NSRF and ACES Power Marketing.		
Essential Power, LLC	Negative	In R1, it is unclear with whom the coordination is conducted. The requirement reads as if the GO or TO is required to coordinate with their own facility. I recommend that the SDT revise the language to make it clear as to who is involved in the coordination. In regards to the facilities to which this Standard is applicable, the term 'bulk power system' used in section 4.2 is ambiguous and is not defined in the current, approved version of the NERC Glossary of Terms. The term should be changed to 'Bulk Electric System', as defined in the Glossary.
Response: The GVSDT thanks you for your comment. The "coordination" specified within R1 is a technical term commonly used in protective relaying departments for a comparative evaluation of the set points and operating characteristics for control equipment and protective relaying equipment. The use of this word here is that connotation rather than one associated with communication between two parties. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Seattle City Light	Negative	New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.

Organization	Yes or No	Question 11 Comment
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Old Dominion Electric Coop.	Negative	Not sure that R2 is written correctly... GO and TO to verify their own verification every five years. Just tell them they must do it every five years, Regions/NERC/FERC should be verifying.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Omaha Public Power District	Negative	OPPD supports MRO NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns.
Dairyland Power Coop.	Negative	Please see comments submitted by MRO NSRF.
Madison Gas and Electric Co.	Negative	Please see MRO NSRF comments
Muscatine Power & Water	Negative	Please see the comments submitted by NSRS for Project 2007-09 Generator Verification.
North Carolina Electric Membership Corp.	Negative	Please see the formal comments submitted by ACES Power Marketing.

Organization	Yes or No	Question 11 Comment
Sunflower Electric Power Corporation	Negative	Please see the formal comments submitted by ACES Power Marketing.
Tenaska, Inc.	Negative	PRC 019 could be difficult to implement given the limited AVR interface/control provided to users by OEMs. More flexibility may be needed in some circumstances.
Response: The GVSDT thanks you for your comment. The SDT assumes the commenter is referring to digital AVR's. If the commenter did not obtain the proper software to interface with the AVR when it was purchased, then there should at least be a commissioning report that specifies the limiter settings. If the entity cannot access these settings, then by default they will not be changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists		
Seattle City Light	Negative	Q11. New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		

Organization	Yes or No	Question 11 Comment
Brazos Electric Power Cooperative, Inc.	Negative	See ACES Power Marketing comments.
Midwest ISO, Inc.	Negative	See comments submitted by MRO NSRF.
New Brunswick System Operator	Negative	See comments submitted by NPCC Reliability Standards committee.
Florida Municipal Power Pool	Negative	See FMPA comments
Lakeland Electric	Negative	See FMPA comments.
Central Electric Power Cooperative	Negative	see Matt Pacobit’s comments from AECI
N.W. Electric Power Cooperative, Inc.	Negative	see Matt Pacobit’s comments from AECI
KAMO Electric Cooperative	Negative	See Matt Pacobit's comments from AECI
Northeast Missouri Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI
M & A Electric Power Cooperative	Negative	See Matt Pacobit's comments from AECI.
Sho-Me Power Electric Cooperative	Negative	See Matt Pacobit's comments from AECI.
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments.

Organization	Yes or No	Question 11 Comment
Public Utility District No. 1 of Lewis County	Negative	Thank you for the opportunity to comment on the proposed standard PRC-019-1. Our utility owns and operated a smaller run-of-river hydroelectric plant with two 35MW units. While I am a firm believer in testing, it can be over done. Many of the new relays and AVR's are electronic based and do not change over the years. Initial plant setup normally verifies coordination of the relaying and ARV limits. Therefore I suggest changing testing requirements in R2 to no more often than 10 years for electronic AVR systems. Classes or training in NERC generator and unit testing in Project 2007-09 would be helpful to Generator Owners, especially smaller GO's.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
Clark Public Utilities	Negative	The effective date section of the standard provides a confusing implementation for a utility that has only one generator. Please address this issue. I suggest that you add the following to end of section 5.1.5, "This section applies to a Generator Owner and Transmission Owner having only one applicable facility."
Response: The GVSDT thanks you for your comment. The SDT disagrees that five years are necessary to perform the required activities on one generator. However, the SDT has modified the implementation schedule to remove the first step (20% in one year), so that entities with one or two units and outage schedules longer than one year will have two years to complete the activities on the first generator.		
Southwest Transmission Cooperative, Inc.	Negative	The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the “verify the existence of the coordination” from Requirement R2. Requirement R1 uses “shall coordinate”. **The SDT has revised R1 and the**

Organization	Yes or No	Question 11 Comment
		wording in the VSL's accordingly. Additional VSLs were added based on increments of tardiness. We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Sunflower Electric Power Corporation	Negative	The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement

Organization	Yes or No	Question 11 Comment
		at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF.
Response: The GVSDT thanks you for your comment. The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.		
Independent Electricity System Operator	Negative	There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification information. **The SDT agrees. The GVSDT has revised the VSLs to include increments of tardiness for each level.** The SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulate din R1, can subject an entity to being found non-compliant twice. This is not acceptable. **Requirement R2 has been restructured so that it only involves addressing changes to the settings or equipment that will affect coordination. The time frame is much different and the VSL's for Requirement R2 have been restructured accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
Southwest Transmission Cooperative, Inc.	Negative	We disagree with the need to include Blackstart Resources within this applicability of this standard. While Blackstart Resources are included in the Statement of Compliance Registry Criteria under criterion III.c.3, their inclusion is primarily to apply the system restoration standards to them. These units are small units that rarely run and simply do not need to be included in this standard. EOP-005-2 R6 already requires the Transmission Operator to verify these units are capable of performing their functions. These functions include supplying real and reactive power, dynamic capability, and controlling voltages and frequency. This seems like it would have to include an analysis of the impact of Protection Systems. Furthermore, these units will be monitored carefully during a restoration given that the operating situation by its very nature is not stable. It is unlikely that Protection System coordination would be a problem in these situations. **The SDT disagrees that Blackstart Resources should be removed from the applicability of this standard. When called upon to operate in their blackstart mode, it would probably be under stressed transmission system conditions that could require the generator to provide reactive power to its limits (either leading or lagging). Given the critical nature of an actual transmission system recovery, having the blackstart generator limiters and protection properly coordinated is essential.** The standard should not be applicable to the bulk power system. Facilities sub-sections 4.2.1, 4.2.2 and 4.2.3 include any facility meeting the criteria that is connected to the bulk power system. First of all, there is great confusion over what constitutes that bulk power system so it makes the standard more ambiguous. Second, the standard will likely now include units that are on subtransmission or distribution systems or even behind the meter and ultimately have little to no impact on reliability. At the very least, the additional costs associated with tracking their compliance will not be commensurate with the reliability benefit. They should not be included unless it can be demonstrated that the reliability benefit of their inclusion outweighs the costs. These sections should be limited to the Bulk Electric System which would prevent the inclusion

Organization	Yes or No	Question 11 Comment
		of these additional units. This would actually also be more consistent with Commission statements in Orders 743 and 693. Originally, the Commission stated in Order 693 that they would enforce standards against the bulk electric system and reaffirmed this in Order 743 with the statement in paragraph 100: "The Commission, the ERO, and the Regional Entities will continue to enforce Reliability Standards for facilities that are included in the bulk electric system." Third, inclusion the Statement of Compliance Registry Criteria in the standard is incomplete, confusing and potentially applies the standard to facilities that NERC has already determined are not material to the reliability of the bulk power system. Criterion III.c.4 is omitted presumably because it is ambiguous. Note 1 which states that the criteria are general and NERC is free to deviate from the criteria to include or exclude facilities that are or are not material to the reliability of the bulk power system. We believe it is reasonable to include examples of satisfactory evidence. It helps to highlight the intent of the drafting team. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn't the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to "systems, equipment or setting changes" within 90 days? We do not believe "shall verify the existence of coordination" accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing "shall verify the existence of coordination" to "shall coordinate". Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind**

Organization	Yes or No	Question 11 Comment
		(equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1. Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. **The SDT believes that "Regional Entity" is the proper Compliance Enforcement Authority and declines to make a change.** The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". **The SDT agrees and has revised the wording in the Severe VSL for Requirement R1 to say "… failed to coordinate equipment capabilities, limiters, and protection…".** We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
Modesto Irrigation District	Negative	We strongly support generator testing and verification, and coordination with protection systems. However, the use of the undefined term “bulk power system” in the standard will lead to needless confusion. Also, we believe the intent of the coordination and testing standards is to recognize the importance to the Bulk Electric System (BES) of all interconnected generators with a capacity greater than 20 MVA. Hence, perhaps interconnected generators of this size should be included in the BES.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Southern Company	Yes	R1, Part 1.1.1 needs clarification. We recommend this be revised to state, “Assuming initial steady state system conditions with the AVR in service, verify the limiters...” Reflect any changes in M1. R1, Part 1.1.2 needs clarification. We recommend this be revised to state, “Confirm the settings determined in Part 1.1.1 have been applied to the in-service equipment.” Reflect any changes in M1. **The wording of R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of “equipment capabilities” throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification** Some consideration of changing the five year recurring verification of the coordination required by R2 to a six year period should be performed so that typical 18 month and 3 year outage schedules will coincide with the requirement periodicity. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity.**

Organization	Yes or No	Question 11 Comment
		In the applicability sections 5.1 and 5.2, we prefer that the percent complete be "of the entities total applicable MVA" rather than "of its applicable Facilities". **The SDT believes it would be more complex for entities to track percentage of MVA than number of units and will not make the requested change.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
PacifiCorp	Yes	1. PacifiCorp does not support the addition of the term "bulk power system" to the various subsections of Section 4.2. - the "Applicability" section. The term is ambiguous and, in this context, fails to provide the clarity afforded by either the previous language ("at greater than or equal to 100 kV") or the defined term of "Bulk Electric System." PacifiCorp suggests maintaining the existing applicability language, including the "directly connected" qualifier so that the language reads substantially as follows (for section 4.2.1): "Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected at the point of interconnection at 100 kV or above." Conforming changes should also be made to section 4.2.2 and 4.2.3.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly. Section 4.2.2 already uses the words "directly connected", no change will be needed. Section 4.2.3 does not use the words "directly connected", however the words used are from the Statement of Compliance Registry Criteria part III.c.2. No change will be made.		
Exelon		1) In the Consideration of Comments on Generator Verification (PRC-019-1) - Project 2007-09 dated 2/22/12 (Question 5 on p 57), Exelon requested that the implementation period by 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.In response to Exelon's comments on Questions 5, the SDT states that "[t]he SDT does not believe the requirement to have 20 percent of

Organization	Yes or No	Question 11 Comment
		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."Exelon does not believe that the SDT fully evaluated the example. Exelon Nuclear is registered with NERC in the RFC Region as a GO/GOP. This registration encompasses 16 generating units which are all nuclear generating units. Exelon Nuclear is also registered with NERC in the SERC Region as a GO/GOP. This registration encompasses only one (1) generating unit which is also a nuclear generating unit. Therefore the explanation given by the SDT to move the nuclear "unit" to the last 20 percent of the implementation period is impractical as it would be for any GO/GOP that has a fleet of all nuclear generating units. **Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year.** 2) PRC-019-1 R1 (or the Applicability section of the Standard) should not apply to facilities currently in service until changes in the protection system are made. Applying this Standard to facilities in service will be a paperwork burden and will have no impact on reliability. It is more reasonable to apply PRC-019-1 R1 to facilities upon changes to the protection system. **The SDT disagrees that addressing miscoordination should be postponed until changes in a protection system are made. Such changes may not occur for decades. If it is determined that a protection system setting change is needed to address miscoordination, that is an easy task to accomplish during a scheduled outage.** 3) The Applicability section should take care to avoid restating language from the BES definition or Compliance Registry criteria. Those documents may be revised which could result in inconsistent applicability and potentially more prescriptive criteria than the registration requirements (i.e., facilities at 20 MVA may not be considered within the scope of the BES based on recent drafts of the revision, and the compliance registry may follow suit). **The inclusion of synchronous condensers makes it necessary to clarify the applicability and restate the**

Organization	Yes or No	Question 11 Comment
		portions of the Statement of Compliance Registry Criteria that apply. 4) The data retention language should similarly avoid restating aspects of the NERC Rules of Procedure (ROP). Revisions to the ROP are made independently and if changed may then create a discrepancy with the Standard creating conflict and confusion. The first paragraph in the data retention section should therefore be deleted. **The SDT agrees with your suggestion. The first two paragraphs have been removed and the remaining wording has been slightly modified such that the Evidence Retention section matches other recently-approved standards.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Indiana Municipal Power Agency		1)In section 4.2. Facilities, IMPA recommends using Bulk Electric System instead of bulk power system. Bulk Electric System is a NERC defined term used in NERC Reliability Standards. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** 2) IMPA believes that this standard does not increase the reliability of the Bulk Electric System and tends to be an expensive and administrative burden to smaller entities. In addition, IMPA does not see how this standard is a performance based standard which NERC determined to be the course of the future for reliability standards. IMPA believes that the industry does not need this standard. **The SDT believes there is a reliability benefit to having protection, limiters, and equipment capabilities properly coordinated. There is no need to recalculate all of the numbers every five years if the entity verifies that the settings and capabilities have not changed. It is possible that the SSSL may change without knowledge of the GO. It is prudent to ensure that coordination with that limit exists. The drafting of this standard began before NERC's Performance Based Standard initiative was initiated.** 3) IMPA does not understand why this needs to be performed once every five

Organization	Yes or No	Question 11 Comment
		years if none of the equipment has been changed. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Texas Reliability Entity		1)Purpose: Suggest replacing the phrase “equipment capabilities” with the NERC-defined term “Facility Ratings”. **The term “Facility Ratings” would imply that all of the equipment within the scope of FAC-008 would have to be evaluated for coordination under this standard. That is not the case. The SDT will not make the suggested change.** 2)R1.1.1: Suggest breaking this up to make the requirement clear.R1.1 Assuming normal AVR control loop and system steady-state operating conditions, verify the following coordination items for each applicable Facility:1.1.1 Limiters and the Protection System for the applicable Facility are set to allow full capability within the Facility Ratings of the applicable Facility and steady-state Stability Limits;1.1.2 Limiters are set to operate before the Protection System of the applicable Facility;1.1.3 The Protection System of the applicable Facility is set to operate, isolate or de-energize equipment, in order to protect equipment from damage when operating conditions exceed Facility Ratings or Stability Limits;1.1.4 Settings determined in Parts 1.1.1 through 1.1.3

Organization	Yes or No	Question 11 Comment
		are applied to in-service equipment. **The wording of R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of "equipment capabilities" throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification** 3)R2: Remove the phrase "the existence of" in the first sentence. Recommend re-wording as follows "Each Generator Owner and Transmission Owner shall verify the coordination identified in Requirement R1.....". **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording has been changed to "perform the coordination…".** 4)R2: Suggest considering removal of the phrase "are expected to" as this is somewhat arbitrary and could lead to differences in application of the Standard. The VSL for R2 has the following phrase "identification or implementation of a change that affected the coordination" that indicates the GO or TO verified ONLY coordination on changes that affected the coordination (rather than what the Requirement states with the phrase "are expected to"). If the phrase "are expected to" is meant to bolster coordination efforts than the VSL language should address the same concept. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.** 5)R2: Suggest re-wording three bullets as follows (leave 4th bullet unchanged): o Voltage regulating equipment settings or component changes o Generating or synchronous condenser Facility Rating changes o Generating or synchronous

Organization	Yes or No	Question 11 Comment
		condenser step-up transformer Facility Rating changes **The SDT agrees with your comment regarding the first bullet and has added "…settings or equipment changes." The SDT disagrees that Facility Ratings is the appropriate term to use with respect to changes in the rotating machine or transformer.** 6)M1: Suggest replacing the phrase "applicable Facility capabilities" with "applicable Facility Ratings". Also, suggest replacing the word "capabilities" with "Facility Ratings" in the 3rd bullet of M1. **The SDT disagrees that Facility Ratings is the correct term in this application. The Facility Rating could be determined by an element other than the generator that is not involved with the coordination activities described in this standard.** 7)VSL R1: Suggest rewording as follows to match the R1 requirement, "The Generator Owner or Transmission Owner failed to coordinate the voltage regulating controls and Protection System settings with the applicable Facility Ratings as specified in Requirement R1." **The SDT agrees and has made the suggested changes to the wording. Additional VSLs were added based on increments of tardiness.** 8)VSL Severe R2: Remove the phrase "the existence of" in both sentences. Recommend re-wording as follows "The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1....." **The SDT agrees and has made the suggested changes to the wording.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Wisconsin Electric Power Company		a. In Requirement R1.1.1 , the requirement to verify that Protection System devices are set to "operate before conditions cause damage to equipment" is not attainable and should be revised or eliminated. The best possible settings cannot guarantee that equipment will not be damaged. The best that can be expected is for protection settings to decrease the risk of damage, or to limit the extent of damage if it occurs. **The wording of R1 has been changed as suggested by many**

Organization	Yes or No	Question 11 Comment
		entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) R1 is a five calendar year verification, b) R2 is a re-verification due to changes in the system, c) use of "equipment capabilities" throughout the standard, d) separating the components of the previous R1 paragraph into subparts R1.1 and R1.2 for clarification b. In Requirement R1.1.2, the requirement to make sure that the limiters and protection settings are applied to in-service equipment is not necessary, and should be removed. It can be expected that professionals in the electric power industry are aware of the need to verify that the settings on in-service equipment are proper. Though errors may occur, this is an obvious aspect of good utility practice and responsible care of assets. Therefore, there is no need for a regulatory requirement. In fact no regulation is able to totally prevent human error. Measure M1 also requires a similar change in this regard. **The changes suggested here are also incorporated as described in the response to your comment a).** c. In Section F Associated Documents, better references would be the following IEEE Power System Relaying Committee documents: 1. "IEEE C37.102-2006 IEEE Guide for AC Generator Protection", and 2. "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. **The SDT thanks the commenter for the suggestion. The documents cited will be added to Section F in the standard**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Consolidated Edison Co. of NY, Inc.		o Section 4.2.1: term "bulk power system" should be replaced with "Bulk Electric System (BES)". BES is the NERC defined term.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has		

Organization	Yes or No	Question 11 Comment
modified the standard accordingly.		
PPL		Comments: a. Change "capabilities" in the third bull-dot under M1 to "ratings." **The SDT disagrees that "ratings" is the correct term. A generator's MVA rating does not fully describe its capabilities, since the actual MVA capability varies depending on the real power operating level. These capabilities are fully described the generator's "Reactive Capability Curve" (a.k.a. "D-Curve").** b. Having limits set before trips, and trips before damage, is a necessary part of the generation plant design process, so the requirements of the proposed standard in this respect are just business as usual. Coordination studies are often performed by third-party contractors, with only the resultant relay settings being in GO possession. We suggest that PRC-019 be made applicable to GOs only for Critical Assets, since damage to a generator outside this category would not imperil BES reliability. **The SDT agrees that the coordination exercise should be performed as part of a new facility design or commissioning. However, the SDT has found that this is not always done, or may have not been done correctly. In addition, there are parameters that are affected by the transmission system (e.g. the SSSL) that may have changed and affected the original coordination.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
MRO NSRF		Facilities listed within 4.2, speak of generation units connected to the BPS. This difference of term does not provide consistency within this set proposed Standard. The BES Drafting Team has established a set of "inclusions" that will "pull in" generation units that may not be connected to the BES. Recommend that BES is used instead of BPS. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** Requiring an entity to verify the existence of coordination every five years as part of Requirement R2 is unnecessary. Rather than try to specify a review schedule, consider allowing entities to develop this schedule internally as a best

Organization	Yes or No	Question 11 Comment
		practice. If the drafting team were to retain this verification time frame, clarification should be included within the Requirement as to whether the five year verification resets itself following a change in coordination identified in R2. In consideration of these changes, recommend R2 be revised as follows: R2. "Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following:" **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Los Angeles Department of Water and Power		In regards to PRC-019-1, Attachment 1- Example of Capabilities, Limiters and Protection on aP-Q Diagram at nominal voltage and frequency, since different entities might have different standards in their Generator Protection System Standards for their generating units, it is not clear if they need to superimpose only some specific protection curves or if they are going to be expected to provide the curves for all the equipment protection wired into their generator protection systems. Additionally, some protection equipment from different OEM's has time-dependent characteristics such as OELs. Since the reactive

Organization	Yes or No	Question 11 Comment
		capability curve represents steady-state limits, representing OEL characteristics on the RCC is not completely straightforward. When providing examples, have you consider the economic impact on implementing those examples?
Response: The GVSDT thanks you for your comment. The GO will be expected to provide the documentation/curves showing the coordination of all In-service equipment, both limiters and protection, wired into their generator protection systems and controls as stated in R1. In regards to representing time-dependent characteristics such as OELs, there are published technical papers on this subject, such as "Coordination of Generator Protection with Generator Excitation Control and Generator Capability", a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee. The SDT has added some of these references to Section G of the standard.		
Luminant Energy Company LLC; Luminant Power		Luminant recommends in Requirement R1 that the coordination with Protection System be modified to reference the "applicable Protection System devices as referenced in Section G". As written, Protection System is all inclusive and would require verification of settings beyond the scope of this standard.
Response: The GVSDT thanks you for your comment. R1.1 identifies the scope to be the following "…the voltage regulating system controls, (including In-service 3 limiters and protection functions) with the applicable Facility capabilities and Protection System settings….". The intention of Section G is to provide some examples of evidence that will support a claim that the elements itemized in R1.1 are coordinated. Each of the elements appearing on the examples of Section G are either parts of the voltage regulating system controls, the Facility capabilities, or the generator Protection System. The wording "settings of the applicable Protection System devices as referenced in Section G" has been added to provide limits on the scope of the verification of settings covered in this standard.		
Manitoba Hydro		Manitoba Hydro is voting negative for the following reason:(1) - Implementation time frames - The testing plans/effective dates for the standards MOD-025, MOD-026, MOD-027, and PRC-019 in Project 2007-09 should be the same to reduce unnecessary outages and to maximize the productivity of site visits. Manitoba Hydro suggests that the implementation plan for MOD-026 be applied

[3] Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 11 Comment</th></tr>
<tr><td></td><td></td><td>to MOD-025, MOD-027 and PRC-019.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The SDT does not believe this standard requires unnecessary outages. It is an exercise in verifying protection and limiter settings and performing an engineering evaluation. To optimize the reliability benefits of this standard, the activities need to be performed prior to the reactive power capability test specified in MOD-025-1, so the implementation schedule for this standard is set by MOD-025.</td></tr>
<tr><td>Seattle City Light</td><td></td><td>New Requirements R2 requires, among other things, for Generator Owners to verify the existence of the identified coordination between the voltage regulating system controls and the relay settings every five years. This timing seems objectionable in the opinion of Seattle City Light, and furthermore it is now included in the Violation Severity Levels to be enforced. The reason for objection is that the coordination is already verified within 90 days following any major system modifications, equipment or setting changes as part of R2, and thus the need for verification every five years seems redundant and unnecessary.</td></tr>
<tr><td colspan="3">Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that Generator Owners will want to verify this coordination prior to performing the reactive capability testing required by MOD-025, which is also set on a five year periodicity. While there are triggers for the Generator Owner to update this coordination when equipment changes take place that will affect the coordination, the SDT believes this would be relatively infrequent. Changes in the transmission system, unknown to the Generator Owner, may affect the Steady State Stability Limit, so the Generator Owner will need to communicate with the Transmission Planner or Transmission Owner to determine if a change in the transmission system characteristics has occurred that would impact the coordination evaluation. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.</td></tr>
<tr><td>Ameren</td><td></td><td>Please clarify that R2 applies to Generating / synch condenser coordination as stated in A.3 in order to avoid confusion with the GO-TO Protection System coordination being addressed under Project 2007-06 and its proposed PRC-027-1. The SDT agrees and has added the words “…with applicable Facilities…” in Requirement R2 similar to the wording in Requirement R1.</td></tr>
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Organization	Yes or No	Question 11 Comment
		(2) We believe that R2 is confusing as written. Please restate with subparts to clarify. Insert 'latter of' before 'identification or implementation' to avoid repeat triggers for the same change. The reality is that the implementation of a change may well lag its identification by years. For a given generator several changes may be identified at different times and then implemented during a common major overhaul or maintenance outage. A ten year periodic coordination review is sufficient if no other change has triggered a review; redoing a study more often than needed distracts valuable resources for other activities more important to BES reliability. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.** We propose:(R2) Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1:(2.1) At least once every ten years; or (2.2) Within 90 calendar days following the latter of identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following ... **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated**

Organization	Yes or No	Question 11 Comment
		into R1. (3) From our perspective High VRF is not justified. We suggest changing to Medium risk which in our opinion is a stretch for the following reasons. (3.1) PRC019 capability, limiters, and protection apply to a specific Element, one generator at a time, and if are not coordinated that single generator may be removed from service or may be damaged. But the loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures. If the generator trips because of loss of field, BES voltage state will actually improve. Furthermore, many generators have very few operating hours per year and pose little risk to the BES. High Risk requirement is not met.(3.2) PRC019 is not comparable to either PRC012 or PRC023. (3.2.1) Loss of a single generator differs from SPS in PRC-012 which trips more than one Element. (3.2.2) The vast majority of the generators under PRC019 have much less capability than the Elements under PRC-023 which are either >200kV or critical BES lines and transformers in PRC-023 which are major Elements. FERC Guideline 3 is not met.(3.3) In an emergency condition, lack of intended coordination could affect the electrical state if many generators tripped. This supports Medium not High for FERC Guideline 4. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.** (4) VSL is misaligned with respect to this standard Facilities and Implementation. (4.1) Please add a % of Facilities threshold in R1 to better match the risk to BES reliability. As proposed, an entity that misses coordination for one 20MVA generator causes a Severe Violation even though that generator may operate <1% of the year and represent <1% of their fleet. (4.1.1) For R1, we suggest thresholds of 5% of the entities Facilities for Lower, 5 to 10% for Moderate, 10 to 15% for High, and >15% for Severe VSL.(4.2) For R2, please replace the time-based (days late) with % of MWh (or MVar-hours for synchronous condensers) during the period of violation to more properly account for aggregate impact.

Organization	Yes or No	Question 11 Comment
		For example, (4.2.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.'(4.2.2) Moderate VSL becomes '...more than 5% and less than 10%'(4.2.3) High VSL becomes '...more than 10% and less than 15%'(4.2.4) Severe VSL becomes '... more than 15%' **The SDT disagrees that structuring the VSL's by percentage of units missed is acceptable. The requirement calls for each unit to be coordinated. Missing one unit is a violation of the requirement.** (5) VRF and VSL need to be applied commensurate with BES reliability risk.(5.1) We believe that in this standard, VRF High and VSL Severe is not justified as drafted, and likely to lead to the unintended consequence of disabling limiters and protection to avoid compliance burden. (5.1.1) Lower VSL becomes 'The Generator Owner or Transmission Owner failed to verify the coordination specified in Requirement R1 on their Facilities producing less than 5% of their total MWh generated (or MVarh for synchronous condensers) during the violation period.'(5.1.2) Moderate VSL becomes '...more than 5% and less than 10%'(5.1.3) High VSL becomes '...more than 10% and less than 15%'(5.1.4) Severe VSL becomes '... more than 15%' **The SDT agrees regarding the VRF. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk. The SDT disagrees that structuring the VSL's by percentage of units missed is acceptable. The requirement calls for each unit to be coordinated. Missing one unit is a violation of the requirement.** (6) Violation Severity Level R2: The increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Also in R2 you need a space between "5years". **The SDT has been informed by NERC that the standard increment is 10 days when the expectation for compliance is 90**

Organization	Yes or No	Question 11 Comment
		days. The SDT has corrected the missing space in "5years". (7) There is no mention of working with the Transmission Planner anywhere in the standard. The TP will be the entity that determines the Steady State Stability Limit. **Information about both the generator and the transmission system is necessary to calculate the SSSL (the formulas necessary to perform the calculation are shown in Section G, Reference). The SDT does not believe the Transmission Planner would be unwilling to provide the appropriate information.** (8) Please replace "Bulk Power System" with "Bulk Electric System" in numerous places. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** (9) We request GVSDT to make all the papers listed in the reference section of the standard readily available on the NERC website. **The SDT agrees that this would be convenient. Unfortunately, copyright laws prohibit this.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Public Utility District No. 1 of Clark County		PRC-019 phases in the implementation based on the requirement to complete a certain percentage of applicable facilities by a certain time. My Utility has only one generator so the 20%, 40%, 60%, and 80% of all applicable units appears to be not applicable. Only the 100% appears to be applicable. Please address this situation so I do not have to make a guess as to when our one generator would need to be compliant with PRC-019. If the applicability date falls within the 100% section of 5.1.5, please indicate so in the applicability section of the standard.
Response: The GVSDT thanks you for your comment. Paragraphs 5.1.1 and 5.2.1 of the Effective Date section have been revised to two years in recognition of entities with few units that may have outage schedules that extend past one year. The use of "at least" in each of the Effective Date subsections recognizes generator and transmission owners with a limited number of facilities.		

Organization	Yes or No	Question 11 Comment
FirstEnergy		R1 - The term "In-service" should not be capitalized
Response: The GVSDT thanks you for your comment. The change has been made as recommended.		
Independent Electricity System Operator		R1 VSL: There is only a SEVERE VSL assigned to Requirement R1, for the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1. This condition does not appear to be consistent with the intent of Requirement R1, which requires the responsible entities to coordinate the voltage regulating system controls, (including In-service limiters and protection functions) with the applicable Facility capabilities and Protection System settings. The parts that follow also prescribe the actions need for verification, not the identification of the existence of the verification information. **The SDT has restructured Requirement R1 to include the five year repetition of evaluating coordination and has restructured the VSL for this requirement accordingly. The words regarding "…existence of coordination…" have been removed.** Note that the SEVERC VSL for Requirement R2 includes the following condition: The Generator Owner or Transmission Owner failed to verify the existence of the coordination specified in Requirement R1 in more than 6 years. This condition is almost identical to the SEVERE VSL for R1, except it has a time component associated with the failure. A failure to verify the existence of the coordination specified in Requirement R1 in more than 6 years, despite it might have implemented the verification exercise stipulated in R1, can subject an entity to being found non-compliant twice. We have a serious concern with this. **Requirement R2 has been restructured so that it only involves addressing changes to the settings or equipment that will affect coordination. The time frame is much different and the VSL's for Requirement R2 have been restructured accordingly.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		

Organization	Yes or No	Question 11 Comment
TransAlta Centralia Generation LLC		R2. Each Generator Owner and Transmission Owner shall verify the existence of the coordination identified in Requirement R1 at least once every five years or within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, Please verify the reason for "at least once every five years". If the existing practice (such as 5 years testing in the WECC region) shows that for those generators without changing any associated equipment the models do not change more than 5 years, it is recommended the duration be longer than 5 years.
Response: The GVSDT thanks you for your comment. The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by requiring coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings. Even though ReliabilityFirst votes in the affirmative, we offer the following comments for consideration: 1. Facilities Section 4.2 a. ReliabilityFirst questions the need to specifically spell out the facilities included within this standard. The thresholds are already understood and consistent with the qualifications as specified in the NERC Statement of Compliance Registry Criteria and proposed NERC BES definition. **The inclusion of synchronous condensers (which are not included in the SCRC) makes it necessary to clarify**

Organization	Yes or No	Question 11 Comment
		the applicability. b. ReliabilityFirst requests clarification on why the term "Bulk Power System" is used rather than "Bulk Electric System." ReliabilityFirst interprets, that by using the term "Bulk Power System", units/plants connected at the 69 kV level would be included in this standard. This is in direct conflict with the proposed NERC definition of BES. **The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.** 2. Requirement R2 a. ReliabilityFirst recommends removing the following language from Requirement R2: "that are expected to affect this coordination." The term "expected" is ambiguous and is hard to measure. **The SDT agrees with your comments and has made appropriate changes to both simplify and enhance R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a reevaluation prior to the scheduled five year cycle.** b. ReliabilityFirst recommends adding the phrase "with applicable Facilities" after the opening phase of, "Each Generator Owner and Transmission Owner." The addition of this language will be consistent with the language in Requirement R1. **The SDT agrees with your comment and has added the words as suggested.** 3. Measure M1 a. The language in Measure M1 is set up more like a requirement /RSAW rather than a Measure. Measures should be set up to provide identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement. Furthermore, the Measure should not introduce new concepts or requirements. ReliabilityFirst recommends the following for consideration: "Each Generator Owner and Transmission Owner with applicable Facilities will have evidence that it coordinated the voltage regulating system

Organization	Yes or No	Question 11 Comment
		with the applicable Facility capabilities and Protection System settings as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.” **The SDT agrees with your comment and has revised Measure M1.** 4. Reference Section a. ReliabilityFirst recommends removing the “Examples of Coordination” from the standard since they are simply guidance (as stated in the note - This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions). Examples would be more appropriately housed within an associated whitepaper, FAQ, guidance document, etc. and should not be housed within a NERC Reliability Standard. **The SDT wants to provide the auditor and the responsible entity with typical examples of evidence that demonstrate compliance with R1 and R2. There already exists in technical publications and textbooks many examples of what a coordinated Protection System looks like.** 5. VSLs and associated Requirements a. When timeframes are referenced within the VSLs (and associated Requirements), ReliabilityFirst recommends strictly using a month format (e.g. 60 months) instead of a year/month format. This would be consistent with various other NERC Reliability Standards. **The time interval specified for evaluation of the coordination (now in Requirement R1) is five calendar years. The SDT feels this gives the Generator Owners flexibility in achieving compliance while working with equipment outage schedules. The SDT feels that defining the interval in months would be more onerous to the Generator Owners with no improvement in grid reliability.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
SERC Planning Standards		The comments expressed herein represent a consensus of the views of the

Organization	Yes or No	Question 11 Comment
Subcommittee		above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers”
Response: The GVSDT thanks you for your comment. The SDT will observe the stated caveat.		
American Electric Power		The purpose statement as provided in the standard is not the same as the one stated in this comment form. **The SDT agrees and apologizes for the confusion. NERC staff revised the wording of the Purpose after the Comment Form was developed.** The VSL for R1 should be graduated. For example, missing one element on a fleet should not be categorized as a severe VSL. Perhaps a system similar to the one (Proposed?) for PRC-005 could be adopted. **The SDT has restructured Requirement R1 such that this requirement now defines the five year interval for evaluation of coordination. As such, the VSL for this requirement has also been restructured and now defines the severity levels in terms of tardiness.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Imperial Irrigation District (IID)		The standard is still difficult to read and determine the applicability to the reliability to the BES. For example, it could not be determined in a first, second, or third reading (with team discussion) whether the standard is suggesting we change the maintenance or operations setting by the manufacturer’s OEM.
Response: The GVSDT thanks you for your comment. The SDT apologizes that the commenter is confused about the intent. The SDT tried to provide some clarity by including examples of how to show coordination. Similar to protection coordination, this standard may require a protection setting or limiter setting to be adjusted if the evaluation indicates they are not properly coordinated. It is up to the equipment owner to determine which setting to change if miscoordination is observed.		
Entergy Services, Inc		There needs to be a requirement that the GO protection coordinate with the steady state stability limit. Entergy recommends inserting “or reach steady state

Organization	Yes or No	Question 11 Comment
		stability limits" after "equipment" in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions. **The wording of Requirement R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) Requirement R1 is a five calendar year verification, b) Requirement R2 is a re-verification due to changes in the system, c) the term "equipment capabilities" is now used consistently throughout the standard, d) the components of the previous Requirement R1 paragraph have been separated into subparts R1.1 and R1.2 for clarification. As suggested, R1 now explicitly states that protection needs to be coordinated with steady state stability limits and that the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions.** Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? Entergy recommend that you stay with a 30 day increment. **The NERC guidelines for VSL's specify a 10 day increment when the expectation is that the activity be done within 90 days.** Also in R2 you need a space between "5years". **The SDT agrees and has made the correction as suggested.**
SERC Dynamic Review Subcommittee (DRS)		There needs to be a requirement that the GO protection coordinate with the steady state stability limit. We recommend inserting "or reach steady state stability limits" after "equipment" in 1.1.1 below. 1.1.1. Verify the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state

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		stability limits assuming normal AVR control loop and system steady state operating conditions. **The wording of Requirement R1 has been changed as suggested by many entities. The changes reflect the various opinions that were expressed in the comments. The changes included the following: a) Requirement R1 is a five calendar year verification, b) Requirement R2 is a re-verification due to changes in the system, c) the term "equipment capabilities" is now used consistently throughout the standard, d) the components of the previous Requirement R1 paragraph have been separated into subparts R1.1 and R1.2 for clarification. As suggested, R1 now explicitly states that protection needs to be coordinated with steady state stability limits and that the limiters are set to operate before the Protection System and the Protection System is set to operate before conditions cause damage to equipment or reach steady state stability limits assuming normal AVR control loop and system steady state operating conditions.** Concerning VSL R2, the increment for days late is typically 30 days. Is there a particular reason the GVSDT chose an increment of 10 days? We recommend that you stay with a 30 day increment. **The NERC guidelines for VSL's specify a 10 day increment when the expectation is that the activity be done within 90 days.** Also in R2 you need a space between "5years". **The SDT agrees and has made the correction as suggested.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Northeast Power Coordinating Council		This Standard is written to verify coordination of generating unit Facility or synchronous voltage regulator controls, limit functions, equipment capabilities and Protection Systems. The Standard, as written, may apply to more generation than intended. The Standard as currently written protects the BPS and applies to generation units that are required to register with NERC in accordance with the Statement of Compliance Registry Criteria (SCRC). The approval of a new BES

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		definition by FERC will define new more limiting inclusion criteria than the (SCRC) for generators and therefore will change the population of generators material to the BES. The unintended consequence is that the current wording of the Standard protects the BPS not the BES and uses the SCRC for defining applicable generators, not the BES definition generator Inclusion Criteria. The Standard in its current form will apply to generators that will not be considered material to the BES and not necessary for the reliability of the Transmission System. Section 4.2.1: term “bulk power system” should be replaced with “Bulk Electric System (BES)”. BES is the NERC defined term.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		
Ingleside Cogeneration LP		We believe that the project team has taken a positive step in R1.1.1 to establish that Protection Systems must operate before the generator or synchronous condenser sustains damage. This may actually be more sensitive than the SSSL - which is a good, but not perfect, proxy for the point at which components may be harmed. In addition, Ingleside Cogeneration LP cannot agree with the applicability section of PRC-019-1, which references generation connected to the “bulk power system” rather than the NERC-defined term “Bulk Electric System”. This bypasses the express intent of the NERC Glossary to carefully describe concepts which otherwise can be unevenly applied at the discretion of Regional audit teams. In fact, this action ignores the work output of Project 2010-17 “Definition of the Bulk Electric System” which was carefully crafted by the entire industry in response to FERC Docket RR09-6-000 - which was issued to eliminate exactly these kinds of ambiguities.
Response: The GVSDT thanks you for your comment. The SDT agrees that Bulk Electric System is the appropriate term and has modified the standard accordingly.		

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ACES Power Standards Collaborators		We do not believe Requirement R2 as written accomplishes the reliability purpose. Isn't the purpose of R2 to compel registered entities to re-verify coordination every five years along with changes to "systems, equipment or setting changes" within 90 days? We do not believe "shall verify the existence of coordination" accomplishes this. We believe that it only compels the registered entity to verify the coordination was performed at some point. It does not compel the entity to verify that coordination reflects current conditions such as Protection System settings. We suggest changing "shall verify the existence of coordination" to "shall coordinate". Furthermore, we think some of the confusion could be eliminated by including the five-year periodicity in Requirement R1 and focusing Requirement R2 on system and equipment changes. **The SDT agrees and has revised the wording in R2 to say "… shall perform the coordination…" The SDT has also moved the five calendar maximum repeat interval to R1 and R2 now deals with changes to the system that require re-verification of the coordination.** Section D.1.1 needs to be updated to reflect that latest approved language for the Compliance Enforcement Authority. **The SDT believes that "Regional Entity" is the proper Compliance Enforcement Authority.** The Severe VSL for Requirement R1 is inconsistent with the requirement. It uses the "verify the existence of the coordination" from Requirement R2. Requirement R1 uses "shall coordinate". **The SDT agrees and has revised the wording in the Severe VSL's for Requirement R1 to say "… failed to coordinate equipment capabilities, limiters, and protection…".** We disagree with the High VRFs for both Requirements R1 and R2. Contrary to the explanation provided in the VRF justification for FERC Guideline 4, violation of either of these requirements by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. Thus, the VRF is not consistent with NERC guideline for a High VRF and is not consistent with FERC guideline 4. For a single violation to lead to

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		BES instability, separation or cascading would require other standards requirements to be violated. NERC VRFs must be assigned by applying the criteria to a single violation of the requirement at a time and not multiple violations. Thus, the case where multiple trips of generators occurred cannot raise this to a High VRF. **The SDT agrees. In reviewing the VRF for R1 and R2, recognizing that loss of a single generator will not directly cause or contribute to instability, separation, or cascading failures; the VRF for these two requirements have been changed to Medium risk.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Public Service Enterprise Group (PSEG)		We have these additional comments: a. Regarding Blackstart Resources, the revision to R4, Part 4.2.4 would only apply to Blackstart Resources that are “material to and designated as part of a Transmission Operator’s restoration plan.” The Glossary definition of Blackstart Resources already requires them to be part of a Transmission Operator’s restoration plan, so that language is redundant and should be removed. Our concern is the requirement that Blackstart Resources also be “material to a Transmission Operator’s restoration plan.” Who would judge a Blackstart Resource’s materiality? The standard leaves this issue open, which is unacceptable. We suggest that Part 4.2.4 be rewritten as follows: “Any generator, regardless of size, that is a Blackstart Resource. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry Criteria. The SDT feels it is best to retain the NERC wording without modification.** b. Typo: in R1, “In-service” (not a Glossary term) should be “in-service.” **The wording has been changed as recommended.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Tacoma Power		What if, during the Implementation Plan, it is discovered that coordination does

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		not exist, but the situation is resolved before the effective dates contained in the Implementation Plan? Would this constitute a violation of PRC-019-1? **The intent of the SDT is that the Generator Owner would address any miscoordination issues discovered during the initial evaluation. This would not be a violation of the standard as long as the evaluation were completed within the schedule outlined in Section 5, Effective Dates.** The Implementation Plan uses the phrase "...shall have verified..."R1.1.1 would require that "...the Protection System is set to operate before conditions cause damage to equipment..." Yet, the NOTE under Section G (Reference) states that "this standard does not require the installation or activation of any of the above limiter or protection functions." The latter statement could be construed (in the extreme case) to permit little or no protection functions, but this would appear to violate R1.1.1. Clarification is requested, as these two portions of the standard appear to conflict. **R1 contains the qualifier "in-service". This limits the applicability of this standard to only those elements that are chosen by the owner to be placed into service.** Under R2, is the 5-year interval (a) 5 calendar years or (b) closer to 1825 calendar days?R2 requires that entities "...verify the existence of the coordination identified in Requirement R1...within 90 calendar days following the identification or implementation of systems, equipment or setting changes that are expected to affect this coordination, including but not limited to the following..." Protection System component changes is listed. If a component is replaced in-kind, is it actually required to verify the existence of the coordination identified in both Requirement R1.1.1 and R1.1.2, or just R1.1.2? Or, would this change be N/A to PRC-019-1 because it is not "...expected to affect this coordination..."? **The periodicity of five calendar years has been integrated into R1, and only "change" triggering events are now covered in R2. The wording of R2 has been crafted such that unless a change "will affect" the coordination, then a like kind (equipment and settings) replacement would not trigger a**

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		reevaluation prior to the scheduled five year cycle. Gross unit nameplate is not an industry defined term. The size of unit required for verification for hydro units should be the FERC defined licensed hydro unit nameplate rating. Aggregate gross nameplate plant/facility capacity for hydro units is not a defined term and may not be the combined unit capacities. It is common for hydro facilities with multiple units have increased head losses or other restrictions that restrict or limit plant capacity below the aggregate gross nameplate capacity. For determining gross aggregate hydro plants and units for verification it should be the FERC defined plant licensed capacity. **The terms "gross nameplate" and "gross aggregate nameplate" are used in the NERC Statement of Compliance Registry Criteria. While the terms are not in the NERC Glossary of Terms (and thus not capitalized in the standard), they are generally understood in industry to be the value indicated on the generator nameplate provided by the manufacturer.**
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Kansas City Power & Light		Applicability section states any generator regardless of size that is a black start resource. This standard should not be applicable to black start diesel generators. **The wording in Part 4.2.4 comes directly from the NERC Statement of Compliance Registry Criteria. The SDT feels it is best to retain the NERC wording without modification.** R2 requires verification every five years. This standard should only require initial verification during the five year implementation period. After the initial verification, no further verification should be required unless system or equipment changes dictate the need to make setting changes and re-verify. **The SDT believes that a five year periodicity for the re-evaluation of this coordination is appropriate. We believe that GO entities will want to verify this coordination prior to performing the testing of MOD-025, which is also set on a five year periodicity. While there are triggers for the GO to update this**

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		coordination when equipment changes take place that will affect the coordination, the GO will need to communicate with the TO for grid system characteristics which may impact the SSSL. Since the SSSL can be the basis for some of the limiter and protection settings of generating equipment, the SDT feels that a five year verification of this characteristic is appropriate. The standard has been revised such that the re-evaluation of the coordination on a five year periodicity has been incorporated into R1.
Response: The GVSDT thanks you for your comment. Please see responses to your specific comments above.		
Oncor Electric Delivery Company		No
SERC Generation Subcommittee		No comment
Puget Sound Energy		None
Dynegy		No

END OF REPORT