NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Generator Verification – MOD-026-1 — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the Second Posting of MOD-026-1, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions. These standards and associated documents were posted for a 45-day public comment period from June 15, 2011 through August 1, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. Also included in this report are comments received from the initial ballots and non-binding polls conducted during the last ten days of the 45-day comment period. There were 66 sets of comments, including comments from approximately 185 different people from approximately 120 companies representing all 10 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 of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT asked stakeholders if they believed any additional generation configurations should be considered for applicability under this standard. None of the comments identified other generation configurations/types that should be covered in the applicability. Several commenters recommend making the standard applicability match the compliance registry while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

- The standard is drafted to provide the proper cost/benefit balance for performing generator verification.
- It is not necessary to have models verified for all units listed in the compliance registry.
- Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

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

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

A few commenters expressed concern that the standard does not require the Generator Owner to notify the Transmission Owner of new equipment and provide the Transmission Planner preliminary models based on OEM design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.

Also in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

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.

The GVSDT received many comments concerning various aspects of the standard. As a result of these comments, the SDT has made a number of modifications to the standard including:

1) Correcting several VSL grammatical errors and ensuring consistency between the VSL “increment for tardiness” time period specified and the Requirement language.

2) An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.

3) The format and column information of Attachment 1 has been revised for clarity.

4) The typographical errors in R2.1.1 language has been corrected to clearly state expectation that "the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance."

5) The language of R2.1.4 has been revised to align with the style of R2.1.6.

6) Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.

7) To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

8) There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability / Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.

As a reminder, the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.

Index to Questions, Comments, and Responses

The Industry Segments are:

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

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

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

2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
11. Chantel Haswell	FPL Group, Inc.	NPCC 5										
12. David Kiguel	Hydro One Networks Inc.	NPCC 1										
13. Michael R. Lombardi	Northeast Utilities	NPCC 1										
14. Randy MacDonald	New Brunswick Power Transmission	NPCC 9										
15. Bruce Metruck	New York Power Authority	NPCC 6										
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
17. Robert Pellegrini	The United Illuminating Company	NPCC 1										
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC 1										
19. Saurabh Saksena	National Grid	NPCC 1										
20. Michael Schiavone	National Grid	NPCC 1										
21. Wayne Sipperly	New York Power Authority	NPCC 5										
22. Donald Weaver	New Brunswick System Operator	NPCC 2										
23. Ben Wu	Orange and Rockland Utilities	NPCC 1										
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC 3										
3. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Tino Zaragoza	IID	WECC	1									
2. Jesus Sammy Alcaraz	IID	WECC	3									
3. Diana Torres	IID	WECC	4									
4. Marcela Caballero	IID	WECC	5									
5. Cathy Bretz	IID	WECC	6									
4. Group	Jason Marshall	ACES Power Members						X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. James Jones	AEPCO/SWTC	WECC	1, 3, 5									
2. Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5									
5. Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
1. Venkataramakrishnan Vinnakota		BC Hydro and Power Authority	WECC	2								
2. Pat G. Harrington		BC Hydro and Power Authority	WECC	3								
3. Clement Ma		BC Hydro and Power Authority	WECC	5								
4. Daniel O'Hearn		BC Hydro and Power Authority	WECC	6								
6. Group	Joe Spencer - SERC staff	SERC Generation Sub-committee (GS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

7.	Group	Tim Brown	Idaho Power - Power Production					X					

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

8.	Group	Jonathan Hayes	SPP Reliability Standards Develpment Team		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers	SPP	1, 3, 5
2.	Craig Henry	Oklahoma Gas and electric	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Louis Guidry	CLECO	SPP	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Lynn Schroeder	Westar energy	SPP 1, 3, 5, 6										
6.	Mahmood Safi	OPPD	SPP 1, 3, 5										
7.	Robert Cox	Lea County Electric	SPP										
8.	Thomas Hestermann	Sunflower Electric	SPP 1										
9.	Valerie Pinamonti	AEP	SPP 1, 3, 5										
10.	Robert Rhodes	Southwest Power Pool	SPP 2										
9.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

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

10.	Group	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
2. Louis Slade			RFC 5, 6										
3. Mike Garton			NPCC 5										
4. Michael Gildea			MRO 5										
5. Matthew Woodzell			SERC 5										
11.	Group	Joe Spencer - SERC staff	Dynamics Review Subcommittee										X
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Paul Camilletti	Santee Cooper	SERC										
2.	Sam Dwyer	Ameren Missouri	SERC										
3.	David Thompson	TVA	SERC										
4.	Robin Wells	LG&E/KU	SERC										
5.	Chris Georgeson - chair	Progress Energy	SERC										
6.	Chris Schaeffer	Duke Energy	SERC										
7.	Dale Goodwine	Duke Energy	SERC										
8.	Brad Haralson	AECI	SERC										
9.	Kumar Mani	Progress Energy	SERC										
10.	Joe Spencer	SERC Reliability Corp	SERC										
12.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				
No additional members listed.													
13.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Bill Duge	FE	RFC	5									
2.	Ken Dresner	FE	RFC	5									
3.	Mike Williams	FE	RFC	5									
4.	Brian Orians	FE	RFC	5									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	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.	Rene Free	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	1

15.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Mueller	PSE&G	RFC	3
2.	Ken Brown	PSE&G	RFC	1
3.	Mikhail Falkovitch	PSEG Fosssil	RFC	5
4.	Peter Doln	PSEG ER&T		6

16.	Group	Annette Bannon	PPL Supply					X					

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

17.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
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										
18.	Group	Mallory Huggins	NERC Staff Review Team										
No additional members listed.													
19.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member		**Additional Organization**	**Region** **Segment Selection**										
1. Rebecca Berdahl		BPA, Long Term Sales and Purchases	WECC 3										
2. Chuck Matthews		BPA, Transmission Planning	WECC 1										
3. Erika Doot		BPA, Generation Support	WECC 3, 5, 6										
4. Mike Alder		BPA, Federal Hydro Projects	WECC 5										
20.	Individual	David Thompson	TVA - GO					X					
21.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
22.	Individual	Bo Jones	Westar Energy	X		X		X	X				
23.	Individual	David Youngblood	Luminant Power					X					
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Scott Sweat	Westinghouse					X					
26.	Individual	Antonio Grayson	Southern Company	X		X			X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	Edward Cambridge	APS	X		X		X					
29.	Individual	Michael Goggin	American Wind Energy Association								X		
30.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
31.	Individual	Bob Casey	Georgia Transmission Corporation	X									
32.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
33.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
34.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
35.	Individual	John Bee on behalf of Exelon	Exelon	X		X		X					
36.	Individual	Eric J Anderson	New York Power Authority	X		X		X					
37.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
38.	Individual	Tom Flynn	Puget Sound Energy	X		X		X					
39.	Individual	Jeanie Doty	Austin Energy					X					
40.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
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41.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
42.	Individual	James R. Keller	We Energies			X	X	X					
43.	Individual	Linda Horn	We Energies			X	X	X					
44.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
45.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
46.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
47.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
48.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
49.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
50.	Individual	Kathleen Goodman	ISO New England Inc.		X								
51.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
52.	Individual	Brad Jones	Luminant Energy						X				
53.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
54.	Individual	Kirit Shah	Ameren	X		X		X	X				
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
56.	Individual	Larry Grimm	Texas Reliability Entity										X
57.	Individual	Anthony Jablonski	RFC										X
58.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
59.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
60.	Individual	Gary Chmiel	GE Energy										
61.	Individual	Barry J Skoras	PPL Electric Utilities	X									
62.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
63.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
64.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
65.	Individual	Armin Klusman	CenterPoint Energy	X									
66.	Individual	Dan Hansen	GenOn Energy					X					

1. **The Applicability section of MOD-026 standard is expanded to include plants/facilities comprised of multiple small units such as variable energy resource plants/facilities. Are you aware of other generation configurations/types that should be covered in the Applicability?**

Summary Consideration: None of the comments identified other generation configurations/types that should be covered in the applicability.

Several commenters recommend making the standard applicability match the compliance registry while other commenters recommend removing the requirement to verify small generator units from the standard applicability. The SDT believes:

- **The standard is drafted to provide the proper cost/benefit balance for performing generator verification.**
- **It is not necessary to have models verified for all units listed in the compliance registry.**
- **Proposed applicability thresholds will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.**

The SDT recognizes that the excitation system model and modeling data is already captured by the MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database. Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation. Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds which correspond to at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification. Concern was raised that the language of R5 could require verification of units with ratings less than the thresholds specified in the registry criteria. The SDT asserts that any unit not included in the standard Applicability and deemed to require verification as justified by the Planning Coordinator must, by definition, satisfy the Registry Criteria threshold established. The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit. This is not the case.

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design data. The SDT reminds that the scope of the draft standard is model verification, which can occur only after the equipment is installed. The standard does not address development of the original model during the equipment commissioning process.

Finally, in response to industry comments, the SDT has inserted a footnote in the standard to make clear that standby generator models are not required to be verified.

Organization	Yes or No	Question 1 Comment
Beaches Energy Services, Florida Municipal Power Pool, Lakeland Electric, City of Green Cove Springs, City of Vero Beach	Negative	Under Applicability - Facilities. The facilities applicability should be deleted altogether. The Statement of Compliance Registry Criteria already describes the Facilities for which a Generator Owner/Operator must register. Inconsistency with the SCRC will just lead to confusion and chaos with no benefit to BES reliability. As written, the standard could allow a Planning Coordinator to sweep in generation that do not meet the registry criteria simply by showing, as footnote 4 describes "evidence that the simulated unit or plant response does not match measured unit or plant response", without a commensurate technical justification for that unit actually having an impact to the stability response of the system. If such a small generator is truly important, the SCRC already has the ability within it to include such generation under III.c.4: "Any generator, regardless of size, that is material to the reliability of the bulk power system." We see no reason to vary from the SCRC. In R5, who determines whether a request is "technically justified"? "? How are disputes around "technical justification" resolved?

Response: The SDT thanks you for your comment. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds that will substantially improve the accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.

Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.

Organization	Yes or No	Question 1 Comment
		Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard. **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.** **Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.**
Lakeland Electric	Negative	The Statement of Compliance Registry Criteria already describes the Facilities for which a Generator Owner / Operator must register. Inconsistency with the SCRC will just lead to confusion and chaos with no benefit to BES reliability
		Response: The SDT thanks you for your comment. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry. **The SDT believes the proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each**

Organization	Yes or No	Question 1 Comment
Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard. **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
Commonwealth of Massachusetts Department of Public Utilities, Northeast Power Coordination Council, Inc., Commonwealth of Massachusetts Dept of Public Utilities	Negative	The Standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could be also be critical in some areas. The applicable criterion should be as in the Compliance Registry. The Standard allows for generators to change equipment and then notify the Transmission Planner of the change.This is unacceptable as it represents a significant relaibility concern. . The Standard still is ambiguous and should contain further definitions and clarification. The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.**		

Organization	Yes or No	Question 1 Comment
The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES. **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.** **Regarding your comment concerning equipment changes triggering a model verification, this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available. Generator Owner development of the original model during the equipment commissioning process – including iterations with transmission entities such as the submittal of preliminary models by the Generator Owner and modifications to preliminary model data should be governed by individual interconnection agreements.** **Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.** **With respect to limiters, the SDT believes coordination of these devices is addressed by another standard.**		
Public Utility District No. 1 of Lewis County	Negative	Having an engineering staff of one at our small hydro, regulary work takes a full time effort. That means plant engineering is limited. With this standard, as with many ourside consultants will have to be hired to comply at a cost estimated over $100k. Too much for a small plant with nothing to gain from effort. Therefore, I believe the threshhold for compliance should be raised. Standard should recognize that standard models are good enough to protect the BES.
Response: The SDT thanks you for your comment. Based on SDT member experiences, standard compliance cost cited is not accurate for one unit and should be substantially less than estimated. Compliance will demonstrate adequacy and efficacy of existing plant equipment; benefiting both the plant and the BES. The applicability proposed by the SDT represents effort to balance costs and benefits. "Standard" models are not adequate which is why this standard is being developed.		
BC Hydro and Power Authority	No	The Applicability section includes Generator Owners and Transmission Planners. If an entity is a Generator Owner, they will meet the NERC Compliance Registry Criteria including MVA criteria. Including phrases in section 4.2 such as "The remainder of the plant as an aggregate", and "For all interconnections: Any technically justified unit requested by the Planning Authority" is confusing and it seems to be expanding the criteria. For example hydroelectric units that don't qualify an entity as GO may be captured here. Also, for the aggregate, a GO may not be able to model and verify the aggregate consistent with the

Organization	Yes or No	Question 1 Comment
		method used by TPs.

Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.

The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.

Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.

Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.

If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.

Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.

The standard Applicability would have to explicitly identify units with ratings less than the Registry Criteria threshold established in order for the Planning Coordinator to be able to justify verification of the unit.

In response to comments received, the phrase, "Remainder of the plant as an aggregate" has been revised with language that is less confusing.

Organization	Yes or No	Question 1 Comment
Idaho Power - Power Production	No	We agree with the need to include wind generation in this standard, however the applicability section seems to be overly complicated. We do not see the relevance of the 80% of connected generation as discussed above. We believe that the NERC generator registry/ BES criteria would be clear and appropriate continent wide for this standard and with many other standards. In addition, we believe that Section 4.2.4 is too open-ended. It appears to open the door for the verification of any sized machine that does not match a response, or for other open-ended reasons. Too open-ended and subjective.

Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.

The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.

The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.

Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.

Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.

The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.

If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.

Regarding your comment concerning Section 4.2.4, the SDT believes, that while this language does allow for additional units to be evaluated, this discretion will be exercised on a limited basis since a technical justification is required. The SDT believes it is necessary to keep this language in the standard for identifying key units that, otherwise, would not be included.

PPL Supply	No	The expression, “Units or plants” in para. 4.2 should be changed to “units” to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at

Organization	Yes or No	Question 1 Comment
		~0.1% CF does not need to test the diesel. Also, eliminate the word "to" in the expression in para. 4.2.1, "For each plant with a gross aggregate nameplate rating greater than to 100 MVA".
Response: The SDT thanks you for your comment. The SDT has inserted a footnote in the standard to make clear that standby generator models are not verified. In response to comments received, the phrase, "remainder of the plant as an aggregate" has been revised with language that is less confusing. The wording in 4.2.1 has been corrected. That you for the correction.		
NERC Staff Review Team	No	We are not aware of other units types at this time, but the applicability should be written broadly enough to not preclude applicability to other types of resources that may be connected in the future.
Response: The SDT thanks you for your comment. The SDT believe Standard language is sufficiently broad not to preclude applicability to other types of resources that may be connected to the BES in the future.		
Independent Electricity System Operator	No	No, we are not aware of any. Similar to our comments on MOD-027-1, the Applicability Section of draft MOD-026-1 standard does not contain specific references to variable energy resource plants/facilities. It only covers generating units and plants of certain sizes for the three (and Quebec) Interconnections without any specificity on generator types. Was it an oversight or did the SDT suggest that the "generating units" suffice to generally include all types of energy resources?
Response: The SDT thanks you for your comment. The SDT strove to make standard language technology neutral and purposely avoided identifying specific generating unit technologies. The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.		
Duke Energy	No	However, an exception should be made for variable energy resources for which models have not yet been fully developed and accepted. Techniques for validation of these devices have not been developed similar to generator excitation model validation tools (EPRI PPPD).
Response: The SDT thanks you for your comment. The SDT believes that models have already been developed to an adequate level of detail and are available in the planning tools. Generic models for variable energy resources have been developed in a collaborative industry effort (led by the WECC Dynamic Modeling Working Groups) and should be validated in the absence of available OEM models. Development efforts are underway to provide suitable techniques for validation of variable energy resources.		

Organization	Yes or No	Question 1 Comment
Luminant Energy	No	I am not aware of any other generation configurations/types that should be covered in the Applicability portion.
Response: The SDT thanks you for your comment.		
Consolidated Edison Co. of NY, Inc.	No	Applicability to Smaller Units:The proposed standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some local areas. The applicable criterion should be the same as those used in the Compliance Registry. No capacity factor exemptions should be allowed without a technical justification.Also see section 4.2, footnote 2. This is a broad exemption, and as we saw recently during the continent-wide heat wave, almost all units within our control area were operating. The requirement is to test once every 10 years. This is not an excessively onerous requirement.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.** **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the**		

Organization	Yes or No	Question 1 Comment
increasing impact renewable generation has on the BES. **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
PPL Electric Utilities	No	The expression, “Units or plants” in para. 4.2 should be changed to “units” to make it clear that a plant with, say, three large fossil units at 90% CF and a standby diesel genset at ~0.1% CF does not need to test the diesel. Also, eliminate the word “to” in the expression in para. 4.2.1, “For each plant with a gross aggregate nameplate rating greater than to 100 MVA”
Response: The SDT thanks you for your comment. The SDT has inserted a footnote in the standard to make clear that standby generator models are not verified. In response to comments received, the phrase, “remainder of the plant as an aggregate” has been revised with language that is less confusing. The wording in 4.2.1 has been corrected. That you for the correction.		
SPP Reliability Standards Develpment Team	No	
MRO's NERC Standards Review Forum	No	
Electric Market Policy	No	
Dynamics Review Subcommittee	No	
FirstEnergy	No	
Public Service Enterprise Group	No	
Bonneville Power Administration	No	
TVA –- GO	No	

Organization	Yes or No	Question 1 Comment
Arizona Public Service Company	No	
Westar Energy	No	
Luminant Power	No	
Progress Energy	No	
Westinghouse	No	
Southern Company	No	
PacifiCorp	No	
American Wind Energy Association	No	
Tri-State Generation and Transmission, Inc.	No	
Wisconsin Public Service Corp	No	
Manitoba Hydro	No	
Exelon	No	
Dynegy Inc.	No	
Austin Energy	No	
Wisconsin Electric	No	
We Energies	No	

Organization	Yes or No	Question 1 Comment
We Energies	No	
Xcel Energy	No	
Great River Energy	No	
US Army Corps of Engineers	No	
Ingleside Cogeneration LP	No	
Southern California Edison Company	No	
Ameren	No	
American Electric Power	No	
GE Energy	No	
American Transmission Company	No	
Northeast Power Coordinating Council	No	
ACES Power Members	No	
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
Georgia Transmission Corporation	Yes	Does Applicability 4.2.4 "Any technically justified unit requested by the Planning Coordinator" override the greater than 5% capacity factor over the last three calendar years statement in 4.2? It should in the case of units needed to prevent FIDVR problems and other peak hour considerations.

Organization	Yes or No	Question 1 Comment
Response: The SDT thanks you for your comment. Paragraph 4.2.4 does provide a method by which a low capacity factor unit could be selected for evaluation.		
ISO New England Inc.	Yes	Generators sized well over 100 MVA with a capacity factor under 5% are numerous in our area of the Eastern Interconnection. These older large generators with a capacity factor below 5% will have a significant impact on electric system performance during stressed conditions with high loads. These generators must not be excluded from the verification requirement. Generators sized under 100 MVA may also be important, what is the justification for the cutoff from the verification requirement at 100 MVA? The applicability criteria in this standard should be the same as the registry requirements.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Also, these units may be excluded from model verification however other standards still require that the data be supplied. **The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification.** **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve the accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds that correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		

Organization	Yes or No	Question 1 Comment
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
RFC	Yes	
Tacoma Power	Yes	
Imperial Irrigation District (IID)	Yes	

2. The current version of the MOD-026 standard has been re-formatted so that it would be more concise and contain only reliability related requirements. Do you agree there are no omissions from the prior draft due to the re-formatting of the standard?

Summary Consideration: None of the comments identified omissions from the prior draft. One commenter suggested that it would be easier to identify omissions if a mapping document was created. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	Negative	We do not agree with the following requirements: i. R1: Standards should stipulate the "what's" not the "how's". To avoid the perception that the requirement is prescribing the "how", we suggest simplifying the language of Requirement R1 by replacing "Instruction on how to obtain" with "Instructions for obtaining". Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process. ii. R2.1: The phrase "models acceptable to its Transmission Planner" begs the question on what is deemed acceptable and what if the GO disagrees with the TP's determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to "in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means "Transmission Planner" rather than "Planning Coordinator" since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate. iv. R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself; a no-disturbance simulation may

Organization	Yes or No	Question 2 Comment
		not result in negligible transients due to other reasons; and finally, a disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. 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 excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP's specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity. v. Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again. vi. The standard does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria but are deemed to have an impact on reliability. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to add this provision to fill a potential reliability gap.
Response: The SDT thanks you for your comment. Since the comment contains multiple concerns, the SDT has paraphrased the comment and is responding to each concern separately for easier understanding and review: **#1. Standard shall stipulate the "what's" and not the "how's"; suggest simplifying the language of R1 by replacing "instructions on how to obtain" with "instructions for obtaining".** **Response: Requirement 1 does describe the "what". The "what" is that upon request, the Transmission Planner is to provide the Generator Owner data or instructions on how to obtain needed information. Recommended language does not change the meaning of the sentence and the SDT does not believe the revision proposed would improve clarity; so the language was not changed.** **#2. Bullet vs. numbers; bullets do not require compliance**		

Organization	Yes or No	Question 2 Comment
		Response: As stated in requirement 1, the three bullets identify instructions and data the Generator Owner can request from the Transmission Planner. The Transmission Planner is only required to provide information requested. The SDT believes standard formatting is correct since the Generator Owner determines what, if any of the information identified is requested from the Transmission Planner. **#3. Not comfortable with the phrase "models acceptable to its transmission planners". Recommend adding a requirement for the Transmission Planner to specify modeling requirements or change the wording in R 2.1 to include "in accordance with models specified by the Transmission Planner".** **Response: Since the Transmission Planner is the user of the models, the models must be acceptable to the Transmission Planner in order to be deemed useful. The first bullet under R1 does require the Transmission Planner to provide instructions on how to obtain the list of acceptable models.** **#4 Why R5 is required? In R5, should it be 'Transmission Planner" rather than "Planning Coordinator". Is this request already covered in R3? If not, what is the technical justification?** **Response: The SDT added requirement R5 because sometimes a planner discovers that a model not covered in the base Applicability, which is a subset of the NERC Registry Criteria, incorrectly represents equipment. Requirement 5 provides a method to validate these models that incorrectly represents equipment and not in the base Applicability but meet the NERC Registry Criteria. This requirement is assigned to the Planning Coordinator to address Generator Owner concern that the Transmission Planner might request a model review without proper justification. The requirement is written to require a higher level of justification for requesting a model review than simply contacting the Generator Owner.** **Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **#5. In R6, having an accurate excitation model does not guarantee meeting requirements R 6.1, 6.2, 6.3 due to the reasons indicated. Suggest that requirement be removed.** **Response: R6.1, R6.2, and R6.3 represent established industry practice for assuring model usability. The positive damping requirement makes the Generator Owner provide a response if a new model introduces negative damping. This requirement recognizes that the equipment must be positively damped during actual operation. Negative damping occurring during simulation indicates incorrect modeling. Initialization errors and oscillation transients without disturbance conditions also indicate incorrect modeling.**

Organization	Yes or No	Question 2 Comment
#6. How to handle settings provided to GO by TP **Response: The Generator Owner is responsible for tuning the equipment and providing the final model settings to the Transmission Planner. As a specific example, the Transmission Planner may ask the Generator Owner to implement a gain that is proven via a gain margin test to not be implementable. The Generator Owner would report the gain actually implemented on the actual equipment.** **#7. Recommend that the verification of generation model parameters be included as part of this standard.** **Response: The SDT agrees generator parameters such as the inertia constant, damping coefficient, saturation parameters, direct & quadrature axis reactance's, and time constants need to be correctly modeled. Since the phrase, "excitation control system" is an IEEE defined term with specific meaning the SDT contends this term incorporates the generation model parameters by definition. The generation model parameters must be correct to successfully verify the excitation control system model. Note that the governor turbine model verification is addressed by the MOD-027 standard. The SDT recognizes the various control systems interact and expects correct modeling data. The purpose of this standard is model verification and not the development of correct modeling parameters. If model verification is not successful, then the modeling parameters are not correct and the Generator Owner will need to identify and correct bad parameters. This standard intentionally avoids specifying how to correct model parameters with expectation the Generator Owner demonstrates that model data is correct.** **#8. Standard does not contain any provision that a TP can request for model verification of units that are deemed to have an impact on reliability? (R5 addresses this question)** **Response: Requirement 5 provides a clause that allows the Planning Coordinator to require model verification of additional units by providing suitable documented evidence. This task was assigned to the Planning Coordinator instead of the Transmission Provider to provide an extra review layer for any request to verify any additional units.** **Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.**		
Brazos Electric Power Cooperative, Inc.	Negative	This standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the

Organization	Yes or No	Question 2 Comment
		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 R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Owner in the standards. Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. Summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the Generator Owner should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Owner should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.

Response: The SDT thanks you for your comment. Since the comment contains multiple concerns, the SDT has paraphrased the comment and is responding to each concern separately for easier understanding and review:

#1. This standard is overly administrative by memorializing the interactions between the Generator Owner, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck

Response: The SDT agrees that R2 is the main requirement for model verification. The purpose of requirements R1, R3, R4, and R5 is to provide processes to assure that the information provided per R2 is useful to the user of the information so that the reliability goal of verifying models that are used in BES security limit determination is met.

#2. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are 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 R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that

Organization	Yes or No	Question 2 Comment
the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6 **Response: R6 language references usability testing which can be readily completed by the Transmission Planner. R6 language is not intended to prevent the Transmission Planner from requesting the Generator Owner to verify information if there is evidence that the model is incorrect. The third bullet of R3 mandates that the Generator Owner must respond to evidence from the Transmission Planner that the modeled response does not match the recorded response and this language allows the Transmission Planner, assuming supporting evidence is available, to request a review at any time.** **#3. If there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the Generator Owner should be able to wait for a system disturbance appropriate enough to verify its model. Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Owner should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.** **Response: The SDT believes 90 days is adequate for the Generator Owner to determine if additional information is available to correct the issue or if model verification is required. The requirements do not require model verification in 90 days, only a plan to perform model verification if needed. Per Attachment 1, the Generator Owner then has 365 days to perform the test or collect an ambient event. The 90 day criteria was established to facilitate dialogue between the Transmission Planner and the Generator Owner.**		
Public Service Enterprise Group	No	If the SDT were to prepare a table showing how the requirements in the prior version were incorporated into the present version and included that in its background information on the standard, this question would be answered.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
Exelon	No	Differences between draft 1 and draft 2 of MOD-026 appear to be significant. Without reading through all 134 pages of comments and how the SDT addressed those comments it is too difficult to tell how the requirements were evaluated and if omissions were intentional or not. Suggest that the SDT prepare either a mapping document or a "redline to previous version" to illustrate changes and disposition of such changes to ensure there are no omissions from the prior draft.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
Independent Electricity System Operator		We are a bit surprised and disappointed that the SDT asks this question. The posted

Organization	Yes or No	Question 2 Comment
		MOD-026-1 Draft 2 is a clean version, not a redline version from last posted, making it difficult for readers to identify where the previous requirements are contained in the revised draft. We understand that a reformatting may render tracked changes to be convoluted and hence a clean version may be a better option. However, in doing so, the SDT should provide a mapping document to show where the previous requirements are mapped into the revised draft standard. Whether or not any requirements were omitted could have been and should have been identified by the SDT through the mapping process rather than by the commenters.
Response: The SDT thanks you for your comment. The SDT did not create a mapping document on account extensive changes were made to the standard for which a mapping document would have limited usefulness.		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
American Electric Power	Yes	AEP is not aware of any omissions from the prior draft due to the re-formatting of the standard.
Response: The SDT thanks you for your comment.		
GE Energy	Yes	GE has no comment.
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
SPP Reliability Standards Develpment Team	Yes	
MRO's NERC Standards Review Forum	Yes	
Dynamics Review Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
PPL Supply	Yes	
NERC Staff Review Team	Yes	
Bonneville Power Administration	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Luminant Power	Yes	
Progress Energy	Yes	
Westinghouse	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Georgia Transmission Corporation	Yes	
Wisconsin Public Service Corp	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
Duke Energy	Yes	
US Army Corps of Engineers	Yes	
Ingleside Cogeneration LP	Yes	
Luminant Energy	Yes	
Southern California Edison Company	Yes	
Ameren	Yes	
RFC	Yes	
PPL Electric Utilities	Yes	
American Transmission Company	Yes	

3. **The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR.**

Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1?

Summary Consideration: The majority of commenters agreed with the SDT 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.

Organization	Yes or No	Question 3 Comment
Manitoba Hydro	Negative	Manitoba Hydro is voting negative for the following reasons: 1)We disagree with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators. 2)Attachment 1 is not clear. Specifically, -the “Condition” in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be ‘verified’ and

Organization	Yes or No	Question 3 Comment
		serve as evidence for multiple units meeting the conditions listed. -the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. -the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then read 'Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is = 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.' 3)For Section 4.2 "Facilities", the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition.

Response: The SDT thanks you for your comment.

1. 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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that:

- **a. 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.**
- **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**

Organization	Yes or No	Question 3 Comment
2. The SDT has revised Attachment 1 to improve clarity. **3. The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term "BES Generating Units and Facilities" is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard applicability.**		
Occidental Chemical	Negative	3. The SDT discussed if MOD-026-1 should also include verification of excitation control systems of synchronous condensers. Synchronous condensers are not currently addressed in the NERC Registry Criteria. Synchronous condensers are not mentioned in the Generation Verification SAR. On an MVA capacity basis, the penetration of synchronous condensers in North America is extremely low. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore, the team decided that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.) in a separate SAR. Do you agree with the proposal to not include the verification of synchronous condensers in MOD-026-1? YES Comments: Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Response: The SDT thanks you for your comment. The SDT agrees with your comment and understands both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.		
Manitoba Hydro (Greg Parent, S N Fernando, Daniel Prowse)	Negative	1)We disagree with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. **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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review**		

Organization	Yes or No	Question 3 Comment
requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: **a. 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.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
MRO's NERC Standards Review Forum	No	Synchronous condensers are installed at locations where they are specifically needed for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.
Response: The SDT thanks you for your comment. **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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore the SDT has decided that:** **a. 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.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
NERC Staff Review Team	No	It is most efficient to address synchronous condensers in the same project as generators given that

Organization	Yes or No	Question 3 Comment
		synchronous condensers have many of the same characteristics as generators. Static var compensators (SVCs) and static compensators (STATCOMs) are sufficiently different from generators and synchronous condensers to be appropriately covered in a separate SAR.Despite the low penetration of synchronous condensers in North America, these devices are most likely installed to extend a dynamic voltage security limit as noted by the drafting team. Due to the importance of these devices, validated models should be required for these devices similar to generators. Reliance on other motivations for equipment owners to validate models is inconsistent with requirements for generators and does not provide appropriate assurance that the equipment owners will validate models necessary for system reliability.

Response: The SDT thanks you for your comment. The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue?"

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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that:

a. **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 which could be 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.**

b. **Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**

Wisconsin Public Service Corp	No	Synchronous condensers are installed at where they are specifically for voltage/VAR control purposes. The excitation performances of these units are thus known to be impactful to the local areas where they are located. If excitation parametric authenticity is of concern in a dynamic simulation study, then it would seem synchronous condenser performances are particularly of significance to their respective local areas. They should be included in the verification effort.

Response: The SDT thanks you for your comment. The SDT believes synchronous condenser model verification will need to be addressed by a

Organization	Yes or No	Question 3 Comment
		standard and the remaining question is "Which standard should address this issue?". 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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: **a. 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 which could be 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.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**
Manitoba Hydro	No	Manitoba Hydro disagrees with the SDTs decision that a more appropriate strategy would be to include synchronous condensers with other transmission system dynamic reactive devices (such as SVCs, STATCOMs, etc.). The testing of the excitation system of a synchronous condenser is identical to the testing of the excitation system of a generator and will likely be planned, performed, documented and reported on by the same testing team responsible for testing the excitation systems of applicable generators. Placing synchronous condensers in the same category with SVCs, STATCOMS, etc. introduces an unnecessary hardship to entities. It is suggested that the standard be re-written to include synchronous condensers within the same applicability MVA rating as generators.
		Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. **The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue?" 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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit. Synchronous condensers do not generate real power as a source of revenue so Transmission Owners paying for synchronous condenser installation**

Organization	Yes or No	Question 3 Comment
and maintenance do so for dynamic voltage support; most likely to extend a dynamic voltage security limit. As such, The Transmission Owner is highly motivated to understand and model synchronous condenser dynamic behavior. Based on this understanding the SDT has decided that: **a. 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 which could be 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.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
Duke Energy	No	These types of reactive resources should be included if of a sufficient size to impact reliability.
Response: The SDT thanks you for your comment. The SDT agrees that in a technical sense generator and synchronous condenser excitation system testing have many similarities however there are several factors that prevent clear resolution of this issue. **The SDT believes synchronous condenser model verification will need to be addressed by a standard and the remaining question is "Which standard should address this issue? Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		
Idaho Power - Power Production	No	
Imperial Irrigation District (IID)	Yes	THERE ARE NO SYNCHRONOUS CONDENSERS INSTALLED AND IN SERVICE WITHIN IID FACILITY.
Response: The SDT thanks you for your comment.		
BC Hydro and Power Authority	Yes	MOD-025 includes synchronous condensers. This doesn't appear to be consistent with the strategy for MOD-026?

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. It is true that synchronous condensers are included in the current draft of MOD-025. The MOD-025 standard addresses steady state modeling but does not contain peer review requirements so the GVSDT believes incorporating synchronous condensers into the MOD-025 standard is a better fit.		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
SPP Reliability Standards Develpment Team	Yes	We agree as long as the SDT creates the new SAR to address such devices including Synchronous condensers.
Response: The SDT thanks you for your comment.		
Dynamics Review Subcommittee	Yes	It is good strategy to include synchronous condensers with other dynamic reactive devices as they all fall under the same category - providing dynamic reactive support.
Response: The SDT thanks you for your comment.		
Public Service Enterprise Group	Yes	The team needs to develop a consistent rationale on synchronous condensers in all of the standards being addressed in Project 2007-09. The team should consider asking the NERC Planning Committee to develop a white paper on the need (or lack of need) for synchronous condenser data.
Response: The SDT thanks you for your comment. Even though Project 2007-09 addresses 5 standards, only two of these standards address verification of generator dynamic models. **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. It is common for Transmission Owners to be the owners of synchronous condensers. As such, the peer review draft requirements would not make sense. Therefore the SDT has decided that:** **a. 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.** **b. Both the NERC Board of Trustees and the NERC Standards Committee have endorsed the plan to have the BES SDT during phase 2 of their work under a new SAR (draft version available on the NERC website) to define BES and the correlation of BES elements with the ERO Statement of Compliance Registry Criteria. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.**		

Organization	Yes or No	Question 3 Comment
Southern Company	Yes	It is possible that the owners of the transmission system dynamic reactive devices (such as synchronous condensers, SVCs, STATCOMs, etc) may not be a NERC registered entity at all. Moreover, it is highly inappropriate to just add equipment not mentioned in the original SAR to the standard. It makes more sense, as SDT suggested, to have a separate SAR to address those transmission system dynamic reactive devices.
Response: The SDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Yes. There is already a significant body of work underway defining the extent of the Bulk Electric System. This determination should rest with the project team responsible for that effort.
Response: The SDT thanks you for your comment. The GVSDT will closely monitor the progress of the BES SDT and make appropriate adjustment as necessary to the Applicability of MOD-026-1 regarding the treatment of Synchronous Condensers.		
Ameren	Yes	Agree that there are relatively few synchronous condensers installed on the system. Including these devices with other dynamic reactive devices such as SVC's and STATCOMs, rather than in this standard, appears to be a good approach.
Response: The SDT thanks you for your comment.		
Consolidated Edison Co. of NY, Inc.	Yes	The inclusion of all reactive resources as BES Elements covered by a separate standard would be consistent with the current draft of the proposed Bulk Electric System (BES) Definition and Designations being proposed by the BES standard drafting team.
Response: The SDT thanks you for your comment.		
American Transmission Company	Yes	ATC believes that synchronous condensers may have significant impact in the areas where they are installed. Therefore, ATC agrees that they should be added to the NERC Compliance Registration Criteria and that a separate SAR should be established to develop a separate reliability standard for synchronous condensers and other dynamic reactive devices.
Response: The SDT thanks you for your comment.		
GE Energy	Yes	GE has no comment

Organization	Yes or No	Question 3 Comment
PPL Supply	Yes	
Bonneville Power Administration	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Luminant Power	Yes	
Progress Energy	Yes	
Westinghouse	Yes	
PacifiCorp	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Georgia Transmission Corporation	Yes	
Oncor Electric Delivery Company LLC	Yes	
Exelon	Yes	
New York Power Authority	Yes	

Organization	Yes or No	Question 3 Comment
Dynegy Inc.	Yes	
Austin Energy	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
US Army Corps of Engineers	Yes	
ISO New England Inc.	Yes	
Luminant Energy	Yes	
Southern California Edison Company	Yes	
American Electric Power	Yes	
RFC	Yes	
Tacoma Power	Yes	
PPL Electric Utilities	Yes	
ACES Power Members	Yes	
Electric Market Policy	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Independent Electricity System Operator		We do not have an opinion on which standard should contain this as long as synchronous condensers are verified.

4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain.

Summary Consideration: As a result of industry comments regarding the SDT's request for questions or concerns that were not covered in the other questions, the SDT has made a number of modifications to the standard including:

1) **Correcting several VSL grammatical errors and ensuring consistency between the VSL "increment for tardiness" time period specified and the Requirement language.**
2) **An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.**
3) **The format and column information of Attachment 1 has been revised for clarity.**
4) **The typographical errors in R2.1.1 language has been corrected to clearly state expectation that the unit model response matches the recorded response for a voltage excursion at the unit's point of interconnection from either a staged test or a measured system disturbance."**
5) **The language of R2.1.4 has been revised to align with the style of R2.1.6.**
6) **Several commenters expressed concern with the new Requirement R5 added to the standard giving the Planning Coordinator authority to require a model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. In addition, R5 language has been revised for clarity.**
7) **To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).**

8) **There was some confusion regarding the treatment of small units at plants. The SDT modified the language in the Applicability / Facilities section for clarity and for consistency to the extent possible with the other draft standards in the Generation Verification effort.**

9) **As a reminder the SDT, in its response to industry comments, points out this standard does not address providing notification of equipment changes nor collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.**

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Negative	We do not agree with the standard as posted, and we have cast a NO vote. We are unable to support the VRFs and VSLs for the standard/requirements that we reject, and we expect the standard to be materially revised which may result in corresponding changes to the VRFs and VSLs.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Sunflower Electric Power Corporation	Negative	We believe that changes are needed for the standard and thus the VSLs and VRFs will require conforming changes.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Southern Company Generation	Negative	VSL for R1 needs work - the requirement specifies 30 days - the VSL doesn't count it tardy until 90 days.
Response: The SDT thanks you for your comment. The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days".		
Western Electricity Coordinating Council	Negative	The timeing requirements in the VSLs for R1 is not in agreement with the timing requirements for providing instructions in Requirement 1. Requirement 1 requires the Transmission Planner to provide instructions within 30 calendar days. However, the Lower VSL starts with a violation for providing the instructions more than 90 days lat but less than 120 days late. What about 31-90 days late. I believe the periods in the four VSLs should be adjusted to start with 31-60 for Lower, 61-90 for Moderate, etc. Other than this issue I support the proposed VRFs and VSLs.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days". The 90 calendar day's response period allows sufficient time for communication to occur between the Generator Owner, Transmission Planner and other entities (such as the software vendor or turbine manufacturer) with respect to obtaining information identified in requirement R1. Limiting the R1 response period to 30 days does not provide any benefit.		
MidAmerican Energy Co.	Negative	Neither the standard nor the VSLs are ready to be approved.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Liberty Electric Power LLC	Negative	Due to the need for changes to the underlying standard.
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be able to support the next posting of the standard.		
Texas Reliability Entity	Negative	(1) According to Requirement R1, the TP must provide instructions and data within 30 days of a request. The Lower VSL for R1 starts at 90 days - it should start at 31 days. (2) The Severe VSL for R2 is very awkwardly worded (triple negative?). (3) The VSLs don't reflect all of the actions required in the Requirements and in Attachment 1. For example, the R3 VSLs only refer to the 90 day initial response, and do not address the 365/180 day requirements set forth in the Attachment.
Response: The SDT thanks you for your comment. **(1) The SDT has corrected the discrepancy identified between Requirement R1 and the associated Lower VSL by changing R1 language to read "within 90 calendar days".** **The 90 calendar day's response period allows sufficient time for communication to occur between the Generator Owner, Transmission Planner and other entities (such as the software vendor or turbine manufacturer) with respect to obtaining information identified in requirement R1. Limiting the R1 response period to 30 days does not provide any benefit.** **(2) The SDT has revised the language for the R2 Severe VSL to eliminate the triple negative.** **(3) In the appropriate VSL statements for Requirement R2, reference language for periodicity timeframe has been revised to state, "periodicity timeframe specified in MOD-026 Attachment 1" in order to establish the proper linkage with the time requirements specified in Attachment 1.**		
Sacramento Municipal Utility District	Negative	This vote is cast to correspond with the position on the standard.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment.		
Indiana Municipal Power Agency	Negative	R4 is missing the VRF and Time Horizon. IMPA recommends “Lower” and “Long-term Planning”.
Response: The SDT thanks you for your comment. The SDT has added VRF and Time Horizon information to Requirement R4.		
Lakeland Electric	Negative	What does "external to the plant" mean as used in several of the requirements (e.g., R1, R2, and R6)? Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied? R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Liberty Electric Power LLC	Negative	This standard should be designed so that a TO needing the information initiates the process with a data request. There is no need to have the GO make the request and then have the TO respond - it adds an extra step and more risk of violation to no purpose.
Response: The SDT thanks you for your comment. The SDT assumes this comment refers to Requirement R1. R1 does not require the Generator Owner to make a request for information from the Transmission Planner. However, since several Generator Owners have expressed a need to obtain data possessed by the Transmission Planner, this requirement simply obligates the Transmission Planner to provide information to the Generator Owner if requested.		
Public Service Electric and Gas Co., PSEG Energy Resources & Trade LLC, PSEG Fossil LLC, Public Service Electric and Gas Co	Negative	This standard has made progress, but there are ambiguities that we addressed in our comments and which the team also addressed on its July 29 Webinar. We recommend that the standard incorporate the suggested comments and the team repost the standard for a round of comments only.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.		
Muscatine Power & Water	Negative	The requirements in this Standards are onerous and burdensome for small Utilities, and we have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to Generator Owners, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. The SDT has tried to separate Transmission Owner and Generator Owner requirements. Many of the requirements are conditional and may not apply to some or all Generator Owner unit's. The SDT agrees there is a cost associated with this standard however, a need to verify excitation system models has been established and well understood by the technical community. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry. **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The standard does not require models to be valid over a wider bandwidth than what has been accomplished in the past.**		
Northern Indiana Public Service Co.	Negative	The related Standard Drafting subteams held a webinar on July 29 where they fielded numerous questions; issues still need to be addressed
Response: The SDT thanks you for your comment. The SDT has revised the standard and believes you may find these changes acceptable and will be		

Organization	Yes or No	Question 4 Comment
able to support the next posting of the standard.		
	Negative	The proposed standard is deficient in the following areas: I do not support verification exemptions for generating units rated 100 MVA and higher that have a capacity factor of less than 5%. These are the generating units that when dispatched, must be capable of synchronizing to the BES in a timely manner and operating reliably at their rated capability when synchronized to the grid. The proposed wording appears to allow generators to modify control and auxiliary system that would result in a change to the generating unit's capability and then notify the Transmission Planner of the change that has occurred. The order of notification and the actual modification of the generating unit is clearly backwards. The generator owner has a requirement to notify the Transmission Planner prior to modify the generating unit, especially if the modification results in a decrease in any aspect of the unit's capability (MW or MVAR) or its response time. The standard should include a requirement that all performance aspects of a machine Power System Stabilizer and limiter be made to responsible Transmission Planner. The proposed standard is not clear on this basic requirement.
Response: The SDT thanks you for your comment. The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. Incremental model improvement for low capacity factor units does not justify the performance cost. This standard deals with modeling the generating unit and does not specify performance such as ability to synchronize in a timely manner for operating reliability. **Regarding changes to control and auxiliary systems, these changes do not affect the excitation system model nor does this standard address them. R4 only addresses changes to excitation control system and pant volt/var control system which will impact model accuracy.** **Regarding the last comment, this standard addresses model verification; in other words, this standard ensures that the model predicted response represents the actual response of the equipment. Per the SAR, this standard is a model verification standard and is not a performance standard.**		
National Association of Regulatory Utility Commissioners	Negative	The NPCC has identified the following issues that need to be resolved: Â· The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. Â· The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available. **Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes it is**		

Organization	Yes or No	Question 4 Comment
following the intent of the SAR in writing this standard as a model verification standard as opposed to a performance standard.		
Wisconsin Energy Corp.	Negative	Staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.
Response: The SDT thanks you for your comment. Staged testing does not require line switching; and instead simply requires injecting a step change signal value into the voltage regulator summing junction of the unit being tested. This testing has minimal impact on the transmission system and does not require transmission operator action.		
Dominion Resources Services, Dominion Virginia Power	Negative	Section 4.2.4 needs to be removed to be consistent with other standards. Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. Section 2.1.6 remove “structure”. R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. Attachment 1 title is missing “M”. Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. Section 4: Applicability should spell out testing exceptions
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines match as something that is equal or similar to another.** **Regarding use of the term “structure” in Section 2.1.6, this language indicates that the “block diagram” is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with “eleven and ten” is no longer an issue in the current draft.** **The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Public Utility District No. 1 of Chelan County	Negative	Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC

Organization	Yes or No	Question 4 Comment
		Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
ISO New England, Inc.	Negative	Please see detailed commeents submitted. Of specific concern, we are voting negative due to: 1. The standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some areas. The applicable criterion should be as in the Compliance Registry. 2. The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. 3. The standard still is ambiguous and should contain further definitions and clarification 4. The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. (1) The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. While these units may be excluded from model verification, other standards still require that the data be supplied. **(2) Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.** **(3) The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.** **(4) Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.**		
SERC Reliability Corporation	Negative	Please see coments of the SERC Dymanics Review Subcommittee.
Response: The SDT thanks you for your comment. Please see the SDT response to the SERC Dynamic Review Subcommittee comment.		
Northeast Utilities	Negative	Opposed with comments: 1) The standard allows for generators with a capacity factor under 5% rated over 100 MVA to be excluded from verification. There are many older generators that meet this criterion that

Organization	Yes or No	Question 4 Comment
		would be critical during stressed system conditions with high loads. Generators under 100 MVA could also be critical in some areas. The applicable criterion should be as in the Compliance Registry. 2) The standard allows for generators to change equipment and then notify the Transmission Planner of the change. This is unacceptable as it represents a significant reliability concern. 3) The standard still is ambiguous and should contain further definitions and clarification 4) The standard should include verification of Power System Stabilizers if installed and limiters.
Response: The SDT Thanks you for your comment. (1) The 5% capacity factor exemption was selected to achieve a balance between the cost and benefits. The SDT believes that there are a limited number of units greater than 100 MVA with a capacity factor of less than 5%. While these units may be excluded from model verification, other standards still require that the data be supplied. **(2) Regarding your comment concerning equipment changes triggering model verification, this standard does not address providing notification of equipment changes or collection of preliminary model data from the equipment manufacturer. The standard addresses verification of models following equipment changes. New equipment models cannot be verified until after the equipment is available.** **(3) The standard is being revised to resolve ambiguities and improve clarity. The SDT will consider incorporating suggested comments. The standard will be posted for comments once the revision process is complete.** **(4) Regarding your comment concerning power system stabilizer verification, the SDT believes the information required by R2.1.6 will adequately define the PSS behavior for study. If instead your comment pertains to the appropriateness of PSS settings or tuning values used, the SDT believes such concerns are beyond the scope of this standard.**		
Oncor Electric Delivery	Negative	Oncor Electric Delivery Company LLC believes that the reporting requirements for the generator owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would blend easily with the current ERCOT Protocols, ERCOT Operating Guides and ERCOT Planning Guide that require ERCOT to be the primary interface with Generation Resources. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Response: The SDT thanks you for your comment. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. Since ERCOT is an exception, a regional variance can be considered. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.		
Nebraska Public Power District	Negative	NPPD supports the comments submitted by the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Response: The SDT thanks you for your comment. Please see the SDT response to the MRO-NSFR.		

Organization	Yes or No	Question 4 Comment
Dominion Resources, Inc.	Negative	Dominion submits a negative ballot for the following reasons: Section 4.2.4 needs to be removed to be consistent with other standards. Section 2.1.1 “match” should be changed to approximate. The model will never exactly match. Section 2.1.6 remove “structure”. R3 bullet 3 “match” should be changed to approximate. The model will never exactly match. Attachment 1 title is missing “M”. Attachment 1 column “Condition” replace eleven and ten with “eleventh” and “tenth”. Section 4: Applicability should spell out testing exceptions
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term “match” is appropriate because the Webster’s dictionary defines match as something that is equal or similar to another.** **Regarding use of the term “structure” in Section 2.1.6, this language indicates that the “block diagram” is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with “eleven and ten” is no longer an issue in the current draft.The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Cowlitz County PUD	Negative	Cowlitz has concerns this Standard may prove too burdensome. For older generator units, it may prove nearly impossible to ever achieve models that will accurately predict actual generator response. However, the greatest stumbling point and reason for the negative vote is the low 75 MVA name plate applicability that appears to be arbitrary. Please present technical reasons why the Western Interconnection should be treated differently than other interconnections.
Response: The SDT thanks you for your comment. The SDT believes the standard is drafted to provide the proper cost/benefit balance for performing generator verification. **The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.** **The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification.** **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.**		

Organization	Yes or No	Question 4 Comment
Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation. **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. As a result, the WECC MVA threshold to achieve 80% or more of the connected MVA in WECC for individual units and plants is 75 MVA. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT also proposes requiring verification of an aggregate plant comprised of several smaller sized units because of the increasing impact renewable generation has on the BES.** **If there is evidence that the model does not match the performance of the equipment, then R3 provides a mechanism for requiring verification.**		
Constellation Power Source Generation, Inc., Constellation Energy Commodities Group	Negative	Constellation Power Generation is voting negative on MOD-026-1 due to the vague language in Requirement 2.1.1. Constellation Power Generation would like the SDT to revisit this requirement with the knowledge that generation facilities do not have the necessary equipment to capture "the recorded response" of the excitation system and plant voltage/var controls to the level of granularity needed to demonstrate that it followed the "plant's model response." Further, generation facilities do not have the proper software to analyze the modeled response, and as such, cannot weigh that response against the recorded response should a facility have the necessary equipment to capture a response to a disturbance.
Response: The SDT thanks you for your comment. The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. While it is true that many generators do not have necessary expertise, this expertise can be developed or hired. Proper software can be purchased to analyze the modeled response – utility grade dynamic simulation software used by Transmission Planners for regional and inter-regional studies does not have to be purchased. Typically, the expert will install temporary recording equipment for testing.		
MidAmerican Energy Co.	Negative	Comment: Given the number and depth of comments at the NERC webinar, the NERC standard is not clear or enforceable. This will generate the need for interpretations and Compliance Application Notices which cause further confusion and enforcement issues. Technical issues are also present. There are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been included in the these model are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren't available, then model traces can't accurately match reality. Older wind farms or foreign manufacturers may not have appropriate models. In short, the state of wind

Organization	Yes or No	Question 4 Comment
		farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.
Response: The SDT thanks you for your comment. The SDT believes that required models have already been developed to an adequate level of detail, and are available in the planning tools. Generic models for VER have been developed in a collaborative industry effort (lead by the WECC Dynamic Modeling Working Groups) and should be validated in the absence of available OEM models. These generic models do include a provision for plant-level voltage control (performed by a plant volt/var management system). If plant voltage control is achieved by a device other than a volt/var management system (such as a STATCOM, SVC, etc), verification should also include models of these devices. Finally, An additional condition, row 12, was added to Attachment 1 (the Periodicity Table) specifying that validation is not required for an excitation control system or plant volt/var control that does not include an active closed loop voltage regulation function. This condition exempts wind and solar plants that do not have the capability to regulate plant voltage or respond to grid voltage fluctuations other than switching capacitor and reactor banks in and out of service.		
Ameren Energy Marketing Co., Amerenue	Negative	Comment (1)The wording for Requirement 2.1.4 should be changed to read "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator". Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.(2)In Requirement R5, the term "technically justified request" needs to be clarified. (3)In Requirement R2.1.3, it should be clarified that "rotational inertia" should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. (4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.(5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.(6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.(7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.(8)Footnote 6 should be a set of sub-requirements for R4.(9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.(10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it's too important in determining which generators must comply.
Response: The SDT thanks you for your comments. **(1) The SDT has revised R2.1.4 and has included the essence of your suggestion.** **(2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.**		

Organization	Yes or No	Question 4 Comment
(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft. **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
Pacific Gas and Electric Company	Negative	As drafted, Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. We suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
CPS Energy	Negative	Applicability should be for the "Generator Owner " and not the "Generator Operators".
Response: The SDT thanks you for your comment. The SDT agrees.		
Integrys Energy Group, Inc.	Negative	o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be

Organization	Yes or No	Question 4 Comment
		determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. In response to your first question the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model could be left up to the experts. The SDT drafted a standard that concentrates on stating "what is required" but without stating "how to accomplish what is required". The standard also includes a peer review process. Based on industry comments, the present draft of the standard maintains this same philosophy. **Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.** **Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.**		
Platte River Power Authority	Negative	o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage

Organization	Yes or No	Question 4 Comment
		relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? o The response content for R4 is ambiguous regarding what the written response should contain. o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping?
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Occidental Chemical	Negative	4. Do you have any other questions or concerns with the proposed standards that have not been addressed? If yes, please explain. YES Comments: MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities. If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response - and have already the recording equipment needed to validate performance.
Response: The SDT thanks you for your comment. The SDT believes that the Generator Owner is in the best position to determine realistic and reasonable model representation of installed equipment. For this reason, the standard gives the Generator Owner authority to determine if the model adequately represents performance of installed equipment. It is not desirable to link this standard with the DME standard under development. Also, the DME standard applies to fault recorders and PMU equipment. Low resolution data is adequate for verification. The SDT agrees that if DME is already in place, especially if it is monitoring the appropriate quantities required for excitation control system verification, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the MVA threshold gross nameplate rating specified for each interconnection and this threshold is intended to emphasize the importance of modeling critical units.		
Manitoba Hydro (Greg Parent, S N Fernando, Daniel Prowse)	Negative	2)Attachment 1 is not clear. Specifically, -the "Condition" in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be 'verified' and serve as evidence for multiple units meeting the conditions listed. -the wording for the

Organization	Yes or No	Question 4 Comment
		allowance of a representative unit to be verified and submitted as evidence for identical units is not clear. - the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect. -We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then read 'Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is = 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.' 3)For Section 4.2 "Facilities", the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition.
Response: The SDT thanks you for your comment. The SDT has substantially revised Attachment 1. Regarding the last question, The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term "BES Generating Units and Facilities" is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard applicability.		
Santee Cooper (Terry Blackwell, James Poston, Lewis Pierce)	Negative	1) On "MOD-026 Attachment 1" under the "Periodicity" column, the method for model verification seems to be the analysis of a "recorded response for a voltage excursion". It should be made clear that this excursion can be accomplished by either a staged test or a measured system disturbance. In some instances, it would be preferable to schedule staged tests with temporarily installed measurement and recording devices over permanently installing equipment to capture a response to a system disturbance. In each case, the goal of ensuring an accurate model will be accomplished. 2) At our generating facilities, it is very rare that voltage regulator or exciter parameters are changed. This generally occurs at periods much greater than ten years. Certainly, the model parameters must be confirmed after adjustment to any settings that would have an effect on the Volt/Var performance of the units. The accuracy of the model data would not be diminished by removing the ten year periodicity.
Response: The SDT thanks you for your comment. (1) The SDT has substantially revised Attachment 1.		

Organization	Yes or No	Question 4 Comment
(2) The SDT believes that a 10 year periodicity is appropriate to ensure there are not unforeseen modeling issues of actual equipment response to a voltage excursion that would necessitate revising the model for improving the accuracy of predicted equipment response. Also, the 10 year periodicity concept was overwhelmingly approved by industry (reference industry response to Question 2 comments for the first posting).		
Tenaska, Inc.	Negative	1) It is unclear whether such testing will lead to better models and improved reliability given all of the other assumptions made in stability studies 2) It is unclear whether a staged test or actual system disturbance or BOTH are required for "verification".
Response: The SDT thanks you for your comment. The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. **The Field Test confirmed model verification will result in accurate models.** **Either a staged test or actual system disturbance data can be used. Both are not required.**		
Ameren Services	Negative	(1)The wording for Requirement 2.1.4 should be changed to read "Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator". Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.(2)In Requirement R5, the term "technically justified request" needs to be clarified. (3)In Requirement R2.1.3, it should be clarified that "rotational inertia" should include all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself. (4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.(5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.(6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.(7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.(8)Footnote 6 should be a set of sub-requirements for R4.(9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.(10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it's too important in determining which generators must comply.
Response: The SDT thanks you for your comments. **(1) The SDT has revised R2.1.4 and has included the essence of your suggestion.** **(2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not**		

Organization	Yes or No	Question 4 Comment
match measured unit or plant response. **(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.** **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
PacifiCorp	Negative	(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage

Organization	Yes or No	Question 4 Comment
		limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to PRC-024 Attachment 2. 2.1.3 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" in PRC-024 Attachment 2. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2. (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. (5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. (6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation.

Organization	Yes or No	Question 4 Comment
		As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies.
Response: This comment addresses the draft PRC-024 standard and has been forwarded to the responsible SDT subteam for consideration and response.		
Imperial Irrigation District (IID)	No	
TVA - GO	No	
Arizona Public Service Company	No	
Luminant Power	No	
Progress Energy	No	
Westinghouse	No	
American Wind Energy Association	No	
Tri-State Generation and Transmission, Inc.	No	

Organization	Yes or No	Question 4 Comment
New York Power Authority	No	
Xcel Energy	No	
US Army Corps of Engineers	No	
Luminant Energy	No	
Tacoma Power	No	
GE Energy	No	GE has no comment for MOD-026
North Carolina Electric Membership Corp., Brazos Electric Power Cooperative, Southwest Transmission Cooperative	Affirmative	While we are voting affirmative for the VSLs and VRFs, conforming changes will be necessary if requirements are modified per our ballot comments.
Response: The SDT thanks you for your comments.		
Old Dominion Electric Coop.	Affirmative	Confirming changes need to be made to the VSL based on changes made in the standard itself.
Response: The SDT thanks you for your comments.		
ACES Power Members	Yes	This standard is highly administrative and full of compliance risks not associated with reliability. The purpose of the standard is to ensure that the GO provides an accurate model to the TP and ultimately to the PC. The requirements unnecessarily document the give and take that must occur between the GO and TP to produce a good model. R2, which essentially requires the GO to provide a good model, is the only requirement needed. Everything else is just documentation related and unnecessary.
Response: The SDT thanks you for your comments. The SDT agrees that R2 is the main requirement for improving reliability. The purpose of requirements R1, R3, R4, and R5 is to provide a peer review process to assure that the information provided per R2 is useful to the user of the information. There are always exceptions however others in the industry believe it is necessary to include these administrative requirements.		
BC Hydro and Power Authority	Yes	1. This standard is still not clear in terms of what constitutes verification of the model and what are related obligations of parties involved. Specifically, it is not logical or technically feasible to request GOs to

Organization	Yes or No	Question 4 Comment
		address any problems with "usability" that TPs may have with the excitation control system model applied in their simulation software. Related Requirements are R3 and R6. The GOs provide accurate model data of their systems during the generator interconnection and facility registration process. Detailed base-line testing is done at that time. For subsequent verifications, GOs would use certain software tools, most likely not the same that the TPs are using, to simulate excitation control system response. This simulated response would be compared with actual equipment response. If traces (signatures) match closely enough, the model is verified. The GO would submit required information to the TP as per R2. At this point, the GOs obligations should be over and subsequently, the GOs should not have a compliance obligation to take part in resolving any issues that the TP may have with the "usability" of their models. Any further involvement by the GOs should be in the spirit of good will and professional courtesy among the parties. In conclusion, GOs should not have compliance obligations to resolve issues related to "usability" of models applied in the TPs power system simulation tool. 2. The idea that GOs "own" the models and are responsible for model modifications and verification still remains controversial for a number of reasons:a. GOs have little need for models and many do not have any expertise in modelling.b. Software tools used by GOs or external consultants for commissioning and verification purposes would not be the same as the tools used by TPsc. TPs would have to work on tuning so the whole exercise would not have a particular value in a technical sense. This is supported by the NERC Event Analysis & Information Exchange staff who noted during the first comment period:"Although verification (not validation) of generator equipment settings and testing should be the responsibility of the GO, validation of generator models response to actual system events should be done by the Reliability Coordinator."Also, NERC's white paper "Power System Model Validation", Dec 2010, expands on this view. It implies that the ultimate responsibility for the usability and accuracy of dynamic models and how they perform in relation to the overall system model is the responsibility of the Transmission Planners, Reliability Coordinators or similar entities. 3. We recommend revising the wording in Requirement R2.1.1 for improved clarity. The way it is written, it strongly implies that the method of verification is based on system disturbance (ambient) monitoring: "Documentation demonstrating the unit or plant's model response matches the recorded response for a Voltage excursion at the generator or plant point of interconnection.4. Requirement 5 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner? Also, we recommend revising the wording in Requirement 5 for improved clarity.5. Attachment 1 Column 6 refers to the Planning Coordinator. Is this a typo and supposed to be the Transmission Planner?

Response: The SDT thanks you for your comment. Regarding your first comment, the SDT believes that model verification has to be a collaborative effort between the Generator Owner and the Transmission Planner. As owner of the model, the standard is drafted such that the Generator Owner has the final word when collaborating with the Transmission Planner. If the Generator Owner cannot resolve the model "usability" issue, with the Transmission Planners dynamic simulation software, then the Generator Owner simply communicates this fact to the Transmission Planner.

Regarding your second comment, the industry affirmed with the first posting of the draft standard that the Generator Owner should be assigned responsibility for the model. The Generator Owner has direct access to the equipment. The Transmission Planner has the simulation software, but

Organization	Yes or No	Question 4 Comment
does not typically have access to the equipment or have testing capabilities. Therefore, the standard includes several Requirements that facilitate interaction between the Generator Owner and the Transmission Planner. **Regarding your third comment, Requirement R2.1.1 has been revised for clarity. Standard references to the Planning Coordinator are correct. The Planning Coordinator was chosen after considering industry comments to the first posting of the draft standard to require a higher level of justification for requesting a model review for a unit not listed in the Applicability section than simply contacting the generator owner.**		
SERC Generation Sub-committee (GS)	Yes	The GS is not responding to MOD-026
Response: The SDT thanks you for your comment.		
Idaho Power – Power Production	Yes	The Requirements direct the GO to send responses, data, inquiry to the Transmission Planner. Should this really be to the Transmission Operator? We understand that the TP will ultimately use the data, however, we believe the data and communications should flow through the TOP.Specifying timeframes for both recording data and providing results is cumbersome. More properly, timeframes and periodicity should be specified only on providing results. If necessary, a limit on the age of the recorded data could be specified.R6.1, R6.2 and R6.3 seems overly prescriptive and of little value. In the process of verifying model data and comparing to recorded results, those 3 conditions are met. If the Transmission Planner has concern about their ability to use the model data in their studies, it is more properly addressed either without specific criteria, or with the specific criteria that the Transmission Planner is unable to reproduce the simulated response contained in the model verification.The requirement of several responses to submit plans to test within 365 days and submit with 180 days (per the periodicity table) seems too long from an system reliability standpoint, particularly where it is the outcome of an observed response to an actual event not matching the predicted response. On the other hand, scheduling a test and model verification within a shorter period of time would be challenging for the GO, particularly those that rely on outside contractors for the model verification work.Any request to verify or retest due to an observed response not matching an actual event should be accompanied by full electronic information (recorded data, simulated output, simulation conditions, model data used by TP).Requirement R1. The first two bullets appear to allow variation between Transmission Planners on acceptable models and software. The list of acceptable models needs to standardized at least across the RRO. In addition, the GO should not need to adjust the model validation and verification work based on the software that the TP uses (what happens when the TP uses multiple software packages?). If the SDT feels there is a need to specify acceptable software, then that should also be standardized. The third bullet should read “All of the Generator Owner’s existing” instead of “Any”. The TP should provide all the information in its database regarding the GO’s facilities, not just “any” piece of it.R2, 2.1. Reference to “models acceptable to its Transmission Planner” is inappropriate, see previous comment. The list of acceptable models needs to be standardized, although

Organization	Yes or No	Question 4 Comment
		situations (rare) where the Generator Owner and Transmission Planner jointly agree to use a model not on the list should be allowed. In particular, the Transmission Planner should not restrict use of any the models on the standardized acceptable list.

Response: The SDT thanks you for your comment. Regarding your first comment, the SDT selected the Transmission Planner to be the single point of communication for model verification issues. The reason for this is that the Transmission Planner maintains the dynamic database used to performed stability assessments that define BES security boundaries.

Regarding your 2nd comment, Attachment 1 specifies that the final model verification has to be provided either 180 or 365 days after the response of the equipment is captured. The SDT believes that this specificity is required in order to ensure a ten year (or less in some scenarios) periodicity.

Regarding your 3rd comment, the Generator Owner is responsible for verifying the recorded equipment response matches the model's predicted response. The Transmission Planner is only responsible for determining if the model is usable.

Regarding your 4th comment, the SDT expects the Transmission Planner and Generator Owner to work together to resolve any issues with the model. The SDT believes that both entities have common motivation to resolve modeling issues and will share relevant technical data.

Regarding your 5th comment, standardizing a list for the RRO is not possible since Transmission Planners within an RRO may utilize different dynamic simulation software packages.

Regarding your 6th comment, the standard is not written to require use of a specific software package.

Regarding your 7th comment, the word "any" is meant to mean that any unit data can be requested. Once a particular unit's data is requested, the Transmission Planner is required to provide the complete dataset associated with that unit's excitation control system and plant volt/var control model.

Regarding your 8th comment, the Transmission Planner has to maintain a list of acceptable models to ensure that the Generator Owner will not supply a model that is not supported by the Transmission Planners' dynamic simulation software.

SPP Reliability Standards Develpment Team	Yes	The applicability of 100 MVA matches MOD027-1 but is inconsistent with MOD025-2 or PRC 019-1. We feel like these should be consistent in every standard included in this project. VSLs for R4 footnote reference needs to be deleted since there is no footnote to reference. We would like to see a more consistent approach to the comment forms and the standard itself. It seems there is room for clean up in the posted standard/comment form.

Response: The SDT thanks you for your comment. The Applicability of MOD-026 and MOD-027 is unique because these are the only standards addressing dynamic model verification. The VSL footnote appears earlier in the standard. The SDT believes it is not necessary to have models verified for all units listed in the compliance registry.

The SDT believes proposed applicability thresholds will substantially improve accuracy of the excitation models and associated Reliability based limits

Organization	Yes or No	Question 4 Comment
determined by dynamic simulation in a cost-effective and time-efficient manner when performing verification. **The SDT recognizes that the excitation system model and modeling data is already captured by MOD-012 and MOD-013 required processes. This information, with few exceptions, creates a quality dynamics database.** **Field Testing initiated by the Phase III-IV SDT has shown that performing the activities specified in the draft standard will improve accuracy of the exciter model used in dynamic simulation.** **Utilizing engineering judgment, based in part on recent experience of entities verifying excitation system models, the SDT is proposing to require verification of excitation systems associated with 80% or greater of the connected MVA in each Interconnection. To accomplish this goal, the SDT has proposed MVA thresholds believed to correspond with at least 80% of the connected MVA in each Interconnection. This concept was overwhelmingly supported by industry in response to the previous posting of the standard.** **The SDT has revised the standard in response to industry comments and hope clean up performed is adequate.**		
MRO's NERC Standards Review Forum	Yes	We have a number of questions and concerns as follows: o It is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost effective for the industry. The transient stability dynamic modeling for excitation control was traditionally developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts required by this standard are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more. o MOD-026 does not account appropriately for the differences between distributed generation and single shaft generation. Aggregate generation that do not have a common excitation and regulator control system (such as wind farms) may pose serious difficulties in meeting system disturbance and / or staged testing. A staged test can be performed for a single shaft unit. However, wind farms may not have a centralized plant or wind farm voltage controller. If that isn't the case, entities may be forced to actually shock the BES to force a disturbance large enough to force a wind farm response. If this is true, then exceptions need to be made. o In addition, there are concerns about the technical development and accuracy of current wind farm models. It is not certain that all manufacturers have fully developed all of the control system models necessary to meet these standards. Type III and Type IV PSS/E generic standard models have all been benchmarked. What has not been

Organization	Yes or No	Question 4 Comment
		included in these models are the wind farm park voltage controllers. While local turbine model controllers will dominate the short term response, the longer term park voltage controls are not represented. Therefore if the models aren't available, then model traces can't accurately match reality. Older wind farms will not have appropriate models. In short, the state of wind farm models hasn't completely developed to match wind farms and specific exemptions for wind farms need to be added to the standard at a minimum.
Response: The SDT thanks you for your comment. In response to your first question, the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model is left to the experts. The SDT drafted a standard that states "what is required" without stating "how to accomplish what is required". This standard also includes a peer review process. Based on industry comments, the present draft of the standard maintains this same philosophy. **Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.** **Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.** **Regarding your fourth comment on distributed generators in a plant (such as a Wind Plant), it is reasonable to expect a small signal disturbance (such as switching a static var bank or changing the tap on a load tap changing transformer) test be performed to exercise response of the plant volt/var controls so data recording can be accomplished for validation efforts. The magnitude of the test disturbance will be determined by the nature of the plant control system type (linear closed-loop or semi-discreet with deadband) installed. The specific nature of the stimulus applied is application dependent and will need to be determined by the validation expert, taking into account availability of devices, system strength and other conditions during the test. However, none of these techniques will adversely impact BES reliability.** **Regarding your final comment on availability of VER plant-level models, Generic models for VER have been developed in a collaborative industry effort (lead by the WECC Dynamic Modeling Working Group) and should be validated if an OEM model is not available. These generic models include provision for plant-level voltage control using a plant volt/var management system. If plant voltage control is achieved by a device other than a volt/var management system (such as a STATCOM, SVC, etc.), verification should also include the models for these devices.**		
Electric Market Policy	Yes	Dominion suggests:MOD-026 Section 4.2.4 needs to be removed to be consistent with other standards.MOD-026 Section 2.1.1 "match" should be changed to approximate. The model will never exactly match.MOD-026 Section 2.1.6 remove "structure".MOD-026 R3 bullet 3 "match" should be changed to approximate. The model will never exactly match.MOD-026 Attachment 1 title is missing "M".MOD-026 Attachment 1 column "Condition" replace eleven and ten with "eleventh" and "tenth".MOD-

Organization	Yes or No	Question 4 Comment
		026 Section 4: Applicability should spell out testing exceptions.
Response: The SDT thanks you for your comment. Section 4.2.4, as drafted, is necessary to identify applicable facilities covered by this standard. Note that the SDT added this Applicability to the draft standard after considering industry comments to the first posting noting concerns that the Applicability section is a subset of the Compliance Registry criteria. **Regarding comments pertaining to R2.1.1 and R3, the SDT believes use of the term "match" is appropriate because the Webster's dictionary defines match as something that is equal or similar to another.** **Regarding use of the term "structure" in Section 2.1.6, this language indicates that the "block diagram" is a necessary part of the information provided by the Generator Owner to the Transmission Planner. Note that the same term is also used in Section 2.1.4 as part of the description for the excitation control system and plant volt/var system.** **The typo in the Attachment 1 title has been corrected.** **Attachment 1 has been substantially revised for clarity and thus the issue with "eleven and ten" is no longer an issue in the current draft.** **The SDT believes that the Attachment 1 (Periodicity Table) is an appropriate document for specifying testing periodicity and exemption criteria.**		
Dynamics Review Subcommittee	Yes	R2: The wording for Part 2.1.4 makes it seem that the required model structure and data only applies to the voltage regulator portion of the excitation system. The DRS recommends that R 2.1.4 be reworded to:"Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator." R5: A "technically justified request" needs to be clarified. We suggest using words similar to those used in the slides associated with this project: "A technical justification that demonstrates, through simulation and/or measured response, that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response."R2.1.3 : The DRS recommends a clarification to "rotational inertia." Please consider the following wording: "Generator (or plant equivalent) model structure and data (such as reactance, time constants, saturation factors, rotational inertia (including all rotating components), or equivalent data)."
Response: The SDT thanks you for your comments. **(1) The SDT has revised R2.1.4 including the essence of your suggestion.** **(2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.** **(3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.**		
LG&E and KU Energy	Yes	Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. LG&E

Organization	Yes or No	Question 4 Comment
		and KU Energy suggests tha the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.
Response: The SDT thanks you for your comment. The SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 90 day period to perform all activities required just to achieve timeframe consistency among the Requirements.		
FirstEnergy	Yes	FirstEnergy provides the following additional comments and suggestions:1. Unfortunately as written this standard may require Generator Owners to purchase software to properly analyze voltage excursions to verify their models. This level of expertise historically existed with the TO/TOP, not the Generator. It will be very difficult for the Generators to develop and maintain this expertise for a verification that will only be run once every 10 years. Also, if additional instrumentation is needed to capture this data, nuclear fleets may be challenged to ensure at least 30% of their applicable units will comply with R2 based on refuel outage schedules.2. Applicability Section 4.2.4 - We do not agree with the Planning Coordinator being able to include additional units. Even though the standard says that the PC would have to show technical justification, it should not be left to their discretion to add an entity's unit as applicable. A regional entity is the only ultimate authority that can make this decision and the PC should go through its Regional Entity to prove this justification. We suggest removing this section. Furthermore, it states that the technical justification would need to be verified. It is not clear who would make this judgment on the validity of the justification.3. We are not clear as to what the standard is referring to when it mentions "volt/var control". 4. In requirement 2.1.1, of R2 it states"2.1.1. Documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance."The SDT should specify the magnitude of the voltage excursion referenced in this section.5. In the SDT notes they make reference to allowance being given for identical (Sister) units but I did not see it anywhere in the standard. Can Generator Owners take credit for Sister units when supplying the model verification? 6. As a general note, the first draft of this standard was reviewed by industry over 2 years ago. It seems like a long time between drafts to expect the industry to review and vote on a standard given that there may be several new personnel in a company that are new to compliance. I would have hoped the team came out with only a comment period at this time.7. Attachment 1 - General Comment - "M" is missing from title of attachment "OD-026 Attachment. Also. We assume that the mentioned "voltage excursion" is in reference to the proposed definition found in the proposed PRC-024-1. If so, it should be capitalized and added to the front of the standard and balloted with the standard.
Response: The SDT thanks you for your comment. The responses below are numbered to match the comments. **1. The standard has been written so that either ambient monitoring or a staged testing can be used. The Generator Owner is not required to have the same software used by the TO/TOP. Also, the Generator Owner is not required to maintain testing expertise. It is a Generator Owner decision to**		

Organization	Yes or No	Question 4 Comment
		maintain testing expertise or hire a consultant (which could include personnel from its Transmission Planner). A staged test typically involves injecting a step change signal into the voltage regulator. Permanent instrumentation/equipment is not required to be installed for staged testing. A laptop PC can be used to record staged testing data. Nuclear units do not need to wait until a refueling outage to accomplish this test. **2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **3. Volt/Var control refers to voltage or var output control at a common coupling point for an entire plant consisting of multiple units, typically comprised of technology that, by itself, does not contain sufficient dynamic var capability (such as wind/solar plants).** **4. The SDT believes specifying a voltage excursion magnitude is prescriptive. The testing expert will determine the voltage excursion magnitude to use during testing. Typically a 1% - 2% voltage excursion will provide adequate results.** **5. Yes, sister unit consideration is included in the Periodicity Table (Attachment 1).** **6. The standard has been revised significantly in response to industry comments and has been sent to ballot to gage the level of industry support existing.** **7. The attachment title has been corrected. The phrase, "voltage excursion" is not a defined term, and does not relate to PRC-024.**
Public Service Enterprise Group	Yes	1. The capacity factor calculation referenced in 4.2 should refer to a future attachment that the team would develop that explains (a) which reliability standard one would use to for a unit's capacity rating (such as MOD-010) for the calculation and (b) a sample calculation.2. In 4.2.4, the sentence "Any technically justified unit requested by the Planning Coordinator" should specify (a) the entities that may develop the technical justification, (b) the entity who will evaluate that technical justification and (c) the criteria for judging whether an excluded unit should be included.3. In R1, first bullet: a. Would the instructions issued by the Transmission Planner on "on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation" cover "acceptable" verification via staged tests and "acceptable" verification by a measured system disturbance per R2.1.1.b. Are Transmission Planners the appropriate entity to determine "acceptability" of models or verification since there are about 120 Transmission Planners registered in the Eastern Interconnection? See the comment below regarding R2.1.14. R2.1.1 addresses verification via either staged tests or a measured system disturbance. However, the standard leaves the judgment of the acceptability of verification performed by a GO to the Transmission Planner. We suggest that the team include an attachment to the standard that provides

Organization	Yes or No	Question 4 Comment
		guidance for how to perform acceptable verification, covering both staged testing and a measured system disturbance.5. R5 is unclear. For example, does the 90-day submission period in 5.1 address submissions under 5.2 and 5.3, or does it require that the GO merely acknowledge receipt of the request within 90 days? Since 5.2 addresses plans to verify a model, why would "corrected" data in 5.3 be due within 90 days? 6. Both R3 and R5 require GO action in response to a notification by a Transmission Planner (R3) or a Planning Coordinator (R5). Can a Transmission Planner or Planning Coordinator require a response from a GO for generators that are not yet verified by the GO per the timetable in section 5? If not, it appears that R3 and R5 should be rewritten to recognize this limitation. 7. The July 29 webinar made clear that generator exciter model verification applies to synchronous generators and the plant volt/var control function applies to non-synchronous generators. It would be helpful if this clarification was made in the standard itself, perhaps in the purpose statement.

Response: The SDT thanks you for your comment. The responses below are numbered to match the comments.

1 To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).

2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.

3. a) The list of acceptable models is simply the type of models that the Transmission Planner will accept. This has nothing to do with the methodology used for recording the plant response to a voltage excursion.

3. b) The SDT believes the Transmission Planner is the appropriate entity.

4. Either the staged test or the ambient test can be used to verify the model. The Generator Operator decides which test is used. Restating for emphasis, the list of acceptable models identified in R1 is the list of model structures that can be used to perform the model verification process and does not address "acceptable methodologies" for performing the model verification.

5. After considering industry comments, the SDT has revised R5 for clarity.

6. No, neither the Transmission Planner nor the Planning Coordinator can invoke Requirement R3 for a unit that has not been verified. Requirement R5 is meant to address units otherwise excluded from the standard Applicability standard; so the Transmission Planner or Planning Coordinator can request model verification for otherwise excluded units.

Organization	Yes or No	Question 4 Comment
7. Plant volt/var controls include plant voltage control systems and/or dynamic var devices other than conventional generators. For example, these types of control systems could apply to wind farm units. Wind farm units include both synchronous and asynchronous (often associated with Type I generic models) units. As such, plant volt/var control can be applied to plants that contain synchronous generators, non-synchronous generators, or a combination of both.		
PPL Supply	Yes	1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:"The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term "verified model(s)" in the R2 Violation Severity Levels should be replaced with, "initial submittal of proposed-verified model(s)". 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026.4. The definition of a "technically justified request" in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.
Response: The SDT thanks you for your comment. **Regarding your first comment, the SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 90 day period to perform all activities required just to achieve timeframe consistency among the Requirements.** **Regarding Comment 2, the SDT has revised verbiage in Part 2.1 to emphasis the end goal of verifying the model. The SDT also points out that**		

Organization	Yes or No	Question 4 Comment
		standard language proposed is for facilitating verification of the dynamic model, and not development of the dynamic model. **Regarding Comment 3, the standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.** **Regarding Comment 4, the "technical justification" is not related to Requirements R6.1 – R6.3. These requirements only address if the model is useable by integrating successfully into the Transmission Planner's dynamic simulation software. Additionally, several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.** **Regarding Comment 5, the "walk down" to correct model parameters could be as simple as identifying in the field that equipment gain or limit setting values are incorrectly represented in the model.**
Florida Municipal Power Agency	Yes	FMPA appreciates the efforts of the SDT to "right-size" the applicability to plants that truly impact the stability response of the system. However, the words used in the draft standard allow a loop-hole to the SDT's intent. Footnote 4 to the Applicability section states: "(a) technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". If a region wishes to include 1 MW generators in the process, all they have to do is show that the unit's actual response does not match the simulated response without a technical justification to show that the 1MW generator has any impact on the actual stability response of the system. The SDT should change the "or" in footnote 4 to "and" meaning that the technical justification needs to include both an impact to a stability limit AND a difference between actual and simulated response.In addition, for R5 and footnote 4, who judges what is and what is not a "technical justification"? For instance, NPCC in their regional UFLS standard proposed to cause 1 MW generators to register and be included in the standards. Does the region have the final say on technical justification?The staged test in R2.1.2 and Attachment 1 that is required if an actual event does not occur is onerous. FMPA believes

Organization	Yes or No	Question 4 Comment
		this "staged test" is impractical and should be eliminated. Within a ten year period, an actual event is likely to occur resulting in a recorded response. If an actual event does not occur, then, the risk of inaccuracy is small and a "staged test" with associated higher risk should not be required to only marginally improve accuracy.
Response: The SDT thanks you for your comment. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review. **Regarding acceptable methods for capturing equipment response to a voltage excursion, either ambient event data or staged testing is acceptable. When performing staged testing typically a 1% – 2% step change in the voltage reference signal is used (even with the unit synchronized to the BES) and this is widely accepted safe industry practice.**		
NERC Staff Review Team	Yes	Validation of the voltage and reactive power response of generating units for significant system disturbances indicates that the dynamics database quality is not as robust as noted in the Background Information posted with this standard. As a result NERC staff offers the following three specific comments for improving the quality of the model database:1) It is not possible to accurately model system voltage and reactive power response with valid models for only 80 percent of the installed system capacity. The standard should be applicable to all units greater than 20 MVA and all plants greater than 75 MVA regardless of interconnection voltage. Per the SDT estimates this will assure accurate modeling for approximately 95 percent of installed capacity.2) We disagree with the exemption for units with <5% capacity factor for the past three years. Some large, less efficient units may only run during peak load conditions when reactive support may be most critical thereby making valid models critical to system reliability during those conditions. While they should not be exempted from the standard, we do believe it may be appropriate to assign these units lower priority in the implementation plan.3) The initial completion of validation for all applicable units and periodicity for model verification should be 5 years, not 10 years. The 10 year time is excessive.Any Functional Model entity that requires the models, including Planning Coordinators, Transmission Operators, and Reliability Coordinators, should be permitted under Requirement R3 to provide notification to the Generator Owner that the model is not usable or that the predicted response did not match the recorded response to a transmission system event. Also, Requirement R3 should permit entities to notify the Generator Owner that the model is not usable for any

Organization	Yes or No	Question 4 Comment
		reason. We recommend removing the list referencing Requirement R6, parts 6.1 through 6.3, because it is not and cannot be an all-inclusive list of problems that could make the model not usable (e.g., the model could cause the simulation software to "freeze").In the first row of the Periodicity Table, transmission of the verified model and documentation to the Transmission Planner should occur within 180 days from the date the recorded response is collected similar to all other rows in the table. There is no apparent basis for the additional time provided in the first row of the table.The violation risk factors associated with Requirements R1 through R6 should be at least medium. Use of invalid models resulting from violation of these standards can produce erroneous results and adversely affect assumptions of the electrical state or capability of the bulk electric system, or the ability to effectively control or restore the bulk electric system, particularly under emergency, abnormal, or restorative conditions. This can result in operating beyond the true stability limits of the system.The models validated by application of this standard are used in both the long-term planning and the operations planning horizon. The time horizon for Requirements R1 through R6 should include the operations planning horizon.In Requirement R6, part 6.2, the reference to negligible transients is not measurable. We recommend modifying this to ". . . results in a response that varies less than the numerical stability of the program used for the simulation."In Requirement R6, part 6.3, the introductory phrase "For an otherwise stable simulation" is not necessary and a potential source of confusion. We recommend deleting this phrase and starting the sentence with "A disturbance simulation results in . . ."The SDT should consider use of the word validation instead of verification and assure that the terms used in this standard are consistent with other standards.

Response: The SDT thanks you for your comment. Regarding your opening statement and Comment 1, although the standard does not require verification of modeled excitation control system and plant volt/var response for all units/plants smaller than the MVA nameplate rating thresholds listed in the Applicability section, it is expected that provided models are accurate. If there are reasons to believe that a unit which does not meet the Applicability criteria does not have an adequate model, there is a process proposed that requires the Generator Owner to review the model, and possibly model verification if the review does not identify why the model is not able to correctly predict equipment response.

Regarding Comment 2, the SDT believes requiring verification of small size MVA units and units with a low (< 5%) capacity factor is not practical and would deplete the industry's limited verification capability for very little reliability benefit as concluded from the field testing data involving 4 regions (WECC, SERC, ERCOT, and the FRCC) initiated by the NERC Phase III-IV SDT and completed July 2007. Units with low capacity factor would seldom be synchronized to the BES during significant events.

Regarding Comment 3, the SDT believes the 10 year period is adequate for both initial verification and repeat verification given that the standard also specifies verification is required when equipment changes are made that would affect the units' excitation control system response.

Regarding Comment 4, the SDT believes that the single point of contact for model issues detailed in Requirement 3 is correctly identified as the Transmission Planner. It is not reasonable to make the Generator Owner interact with several Functional Model Entities when only one interaction, specifically the Transmission Planner, is necessary. Also, the second bullet paragraph of R3 (…identifying technical concerns with the verification documentation related to the excitation control system and plant volt/var control1 system function model…) allows the Transmission Planner to

Organization	Yes or No	Question 4 Comment
request the Generator Owner provide a response for all reasonable modeling issues that can occur. **Regarding Comment 5, the SDT points out that if any of the Requirement 6 Parts are not achievable, resulting in "software freezing" or countless other issues, then the Transmission Planner will determine that the model is not usable. In other words, the cause of the issue does not matter. What matters is the model does not function correctly to satisfy each of the three tests specified.** **Regarding Comment 6, the reason why the SDT is proposing additional time is because this condition is the one which will recur during the normal, ten year model verification cycle. There is no reason to suspect that the model parameters will need significant adjustment since the last verification performed. The SDT believes that allowing sufficient time to make sure that the last yet critical step of model verification (which is refining the model to make sure that predicted response matches the actual response of the equipment) is performed correctly.** **Regarding Comment 7, the SDT has changed the VRF for R2 and R6 from low to medium. R1 is administrative in nature in making sure that that the Generator Owner has access to data needed to perform model verification per R2. R3 is an administrative peer review requirement. R4 and R5 are also administrative in defining the processes in which a Generator Owner communicates with a transmission entity to either provide updated model data or to commit to verifying the model per R2.** **Regarding Comment 8, since model verification activities typically take months, if not years to perform, the time horizon of "Long Term Planning" is appropriate.** **Regarding Comment 9, the SDT is not aware of any industry practice that takes into account the numerical stability of the simulation program. It is left to the judgment of the expert reviewing the study results to determine if the transients identified are negligible.** **Regarding Comment 10, utilizing a stable simulation is necessary for determining if the model will adversely impact the robustness of any dynamic modeling performed. If an unstable simulation is used as basis, then there is no way to determine the additional negative response of the model when assessing usability.** **Regarding Comment 11, the SDT believes the term "verification" is an appropriate term. The word verify means, "to determine or test the accuracy of" whereas verification means "the act of verifying". Also, since this term is not capitalized, the context does not have to be exactly relevant to other standards.**		
Bonneville Power Administration	Yes	MOD-026: By making Transmission Planners responsible for generator verification instead of regional entities, it may be more difficult to produce integrated regional models.The standard should also apply to Regional Coordinators to ensure consistent generator verification requirements within regions.
Response: The SDT thanks you for your comment. Integrated regional models have been constructed for quite some time with a large number of participants submitting dynamic models. Because this standard will result in enhancing the validity of dynamic models, the SDT believes that this standard will actually enhance the process of creating integrated regional dynamic databases and load flows.		
Westar Energy	Yes	The applicability in this standard (â‰¥100 MVA) is consistent with the applicability in MOD-027-1. However, the applicability in this standard is not consistent with MOD-025-2 and PRC-019-1. We propose

Organization	Yes or No	Question 4 Comment
		that the SDT revise the applicability to be consistent between all of the standards included in this project.
Response: The SDT thanks you for your comment. The Applicability of MOD-026 and MOD-027 is unique because these are the only standards addressing generator dynamic model verification. Therefore, the SDT believes that consistency between the Applicability Sections of these two standards make sense. The SDT also thought it best not to force the Applicability to be the same in the other standards that address distinctly different subject matter.		
Southern Company	Yes	1) We question how field tests can be performed on aggregation based facilities. We recommend removing the requirement for developing models for the aggregation of units < 20 MVA for conventional units. 2) Isn't R2.1.3 already required of the GO in MOD-012 (dynamic data on generators) 3) The timing of R5 requirement (90 days) seems to contradict with the schedule for modeling in Attachment 1 (1 1/2 years) for PC initiated model reviews. 4) The background section indicates that the PC can request a unit not in the applicability scope (page 2, last paragraph), but R5 doesn't say this. The wording on R5 indicates that the PC can request a review of an existing model. 5) Attachment 1 is difficult to use. Please cross reference the requirement that goes with each row of the periodicity table Attachment 1. Please add row numbers to the table. Please use column 1 to briefly label the conditions that controls the applibility of the row (for example - the row including the exceptions could be labeled SISTER UNITS) 6) It is suggested to review the order in which the requirements are currently numbered. The current R3 seems to be out of place (should occur after the requirement that is currently R6). This will more closely match the flow of how the process will work. 7) VSL for R1 needs work - the requirement specifies 30 days - the VSL doesn't count it tardy until 90 days. 8) The Sister concept needs to be mentioned in the applicability section 9) The exception rule in Attachment 1 should include Sister units at different geographic sites in addition to those at the same site. 10) The exception rule in Attachment 1 should not be limited to 350MVA - if units are identical, then the sister concept should apply. 11) The first bullet of R1 needs to make "model" plural ("models") for the grammer to be correct.12) As the requirement of R4 is not a response to a request, we suggest changing the wording of the text in M4 from "show that it provided a written response (...) submitted within 180" to "show that it submitted communication (...) within 180", where (...) is shown to indicate no change to the parenthetical element.13) As requirement R6 is an evaluation of the verified model by the TP, we suggest changing the wording of the text in R6 from "show that it provided a written response" to "show that it provided an evaulation of the submitted model".
Response: The SDT thanks you for your comment. The responses below are numbered to match the comments. **1. The SDT agrees with this point and has modified the language that inadvertently indicated that mixed plants containing conventional units less than 20MVA had to be tested as an aggregate. The language has been modified to allow, but not require, aggregation by type. This can be accomplished by verifying one unit, then utilizing the sister/proxy unit consideration specified in Attachment 1 for the remaining units of the same type. However, as an option if technically feasible, units can still be tested as an aggregate.**		

Organization	Yes or No	Question 4 Comment
		2. The SDT is requiring the Generator Owner to include in the model verification documentation submitted to the Transmission Planner the generator model information, including the model structure and data that was used for verifying the excitation control system (which is a closed loop system). **3. The language in Section 5.1 has been revised for clarity.** **4. The SDT revised the language of R5 to make it clear that the Planning Coordinator, with technical justification, can specify a unit for model review that is not listed in the Applicability Section.** **5. The SDT added applicable Requirement references to the conditions identified in Attachment 1. The SDT believes these additions are sufficient. It should be noted that the use of the terms "sister" or "proxy" unit has deliberately been avoided in the standard since this language is considered "folksy".** **6. The SDT recognizes that the sequencing of the Requirements to the degree that is necessary for any particular unit model is subjective. The SDT believes the current order of standard Requirements is reasonable.** **7. The VSL's have been revised for consistency.** **8. The sister unit concept is more appropriate to include in the Attachment 1 (Periodicity Table) since it is an exemption that can be utilized by the Generator Owner.** **9. The SDT respectfully asserts that the "same physical location" requirement is necessary since this language provides a strong indication of equipment and settings similarity (which can be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in different geographic locations or regions with different operating procedures/requirements (e.g. having the PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** **10. In response to industry comments received, the SDT raised the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA thresholds are critical to BES reliability and should have the excitation control system model verified at least once each decade.** **11. The SDT corrected the use of the term "models" in the first bullet of R1.** **12. The SDT revised the measure to address your comment.** **13. The SDT believes that the word "evaluation" could be taken out of context. The SDT did revise Requirement language to address your concern.**
PacifiCorp	Yes	Modeling wind generation without a developed generic model is a concern. If the generic models are not developed once the standard is effective are exceptions going to be made to accommodate this?

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. Generic models are available and there are efforts, as detailed in the Background Information associated with this posting, that are expected to result in more robust models. Requirement R2.1.1 states that the Generator Owner is required to produce documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance. Since the Generator Owner has the final say in determining if the match is adequate or not, to the extent that non-proprietary models can be used to "match" the recorded response from the actual equipment, then that will be sufficient for compliance with the Requirements.		
Georgia Transmission Corporation	Yes	Should references to Planning Coordinator be changed to Transmission Planner (4.2.4 and R5)? Or, should Planning Coordinator be added as a functional entity?Have software manufacturers agreed to provide their models as described in R1?
Response: The SDT thanks you for your comment. The Planning Coordinator is referenced in the standard, but is not responsible for any of the Requirements and therefore is not listed in the Applicability section. **The software manufacturers with dynamic simulation packages used with the Interconnection dynamic stability databases have agreed to provide their models described in R1.**		
Wisconsin Public Service Corp	Yes	We have a number of questions and concerns as follows: o While the Standard uses the word "verified" and "verification" loosely, it is not precisely clear what a GO would have to do to satisfy the verification requirements in R2. Would each of the Time Constants, Forward and/or Feedback Gains, Dead-band Excitation Limits, Saturation Characteristics, etc. to be determined separately each on its own? Or are these parameters taken as a whole so long as their combined effect produces a response characteristic in a simulation that matches the recorded test response during an off-line step-input test? o If a simulation study results in response characteristics that does not match an off-line step input test response, can the GO arbitrarily adjust one or more of the model parametric values to produce a matching response, and send the Transmission Planner these adjusted values as the model data? o We have concern about whether this Standard is cost efficient to the industry. The transient stability dynamic modeling for excitation control was developed under the assumption of limited bandwidth validity and approximations. The other equipment models in the simulation, e.g. generators, prime-mover controls, SVCs, HVDC Converters, etc. are all approximations without any correlated degree of accuracies in comparison to each other. On the other hand, the verification efforts are expected to cost quite a bit to GOs, especially for older units whose vendors/manufacturers may not even be in existence any more.
Response: The SDT thanks you for your comment. In response to your first question the SDT has drafted the standard with minimal technical specificity so that the actual mechanics of verifying the model could be left up to the experts. The SDT drafted a standard that concentrates on stating "what is required" but without stating "how to accomplish what is required". The standard also includes a peer review process. Based on industry		

Organization	Yes or No	Question 4 Comment
comments, the present draft of the standard maintains this same philosophy. **Regarding your second comment, arbitrary large adjustment of model parameters without a valid technical reason is not appropriate. Minor adjustments to model parameters that are within expected tolerances may be appropriate.** **Regarding your third comment, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner.**		
Manitoba Hydro	Yes	1)For Section 4.2 Facilities, the section should refer to 'BES Generating Units and Facilities' instead of restating components of the proposed BES definition.2)Attachment 1 is not clear. Specifically, -the "Condition" in the first row is not a condition and is not consistent with the remaining rows. -Row 1 suggests that there are no exceptions for submitting a recorded response of a voltage excursion, but Row 2 contradicts this by allowing a single unit to be 'verified' and serve as evidence for multiple units meeting the conditions listed.-the wording for the allowance of a representative unit to be verified and submitted as evidence for identical units is not clear.-the periodicity for row 1 suggests that a recorded response for a voltage excursion shall be collected 'with the verified model' which is incorrect.-We suggest the following. A statement that precedes the Attachment 1 table should be added that reads 'For all Existing Generating Units - a recorded response for a voltage excursion shall be collected during a ten calendar year (January - December) period from the effective date of this standard and the documentation transmitted to the Transmission Planner no more than 365 calendar days from the date that the recorded response was collected unless otherwise specified by the table below. For all newly installed Generating Units - a recorded response for a voltage excursion shall be collected and the verified model and documentation transmitted to the Transmission Planner no more than 180 calendar days of the unit in service date unless specified otherwise specified by the table below. ' Row 1 should then be Facility - Existing Generating Unit, Condition - All existing generating units unless the following exception applies: If multiple units have the same MVA rating that is â‰¤ 350 MVA, and they have identical applicable components and settings, and they are sited at the same physical location, verification of one representative unit is sufficient for all such units. Verification of a different representative unit should be completed each cycle, Periodicity - not required for any units except one representative unit.
Response: The SDT thanks you for your comment. **(1) The SDT intentionally established the standard applicability as a subset of generators included in the NERC Registry Criteria. The term "BES Generating Units and Facilities" is not specific enough for compliance. There are regional differences that prevent use of this term in defining standard**		

Organization	Yes or No	Question 4 Comment
applicability. **(2) The SDT has significantly revised Attachment 1 to improve clarity.**		
Oncor Electric Delivery Company LLC	Yes	The implementation plan call for a certain % of applicable plants to be in compliance over a certain number of years. Since plants may be registered individually, it is unclear what the term applicable plants is referring to in the implementation phase.Oncor takes the position that the reporting requirements for the Generator Owner as specified in R1, R2,R3,R4,R5 & R6 should be to the Planning Authority and not the Transmission Planner in the ERCOT Region. This would align with the current protocols, operating guide and planning guide that require the ERCOT ISO to be the primary interface with Generation Resources. The ERCOT ISO is registered as the Planning Authority. One option would be a regional variance that would point to the Planning Authority or Planning Coordinator in lieu of the Transmission Planner.
Response: The SDT thanks you for your comment. **The Implementation Plan actually calls for a certain percentage of applicable units on an MVA basis (not plants) to be in compliance over a certain number of years. Specifically for ERCOT, a unit is applicable in the draft standard if: (a) a gross nameplate rating greater than or equal to 50 MVA, connected at the point of interconnection with rating greater than or equal to 100 kV, OR (b) units greater than 20 MVA if it is located at a plant with a gross aggregate nameplate rating greater than or equal to 75 MVA, connected at the same point of interconnection with rating greater than or equal to 100 kV, OR (c) plants (i.e. all the units in each applicable plant) with a gross aggregate nameplate rating greater than 75 MVA comprised of units that have a gross nameplate rating less than or equal to 20 MVA, connected at the same point of interconnection at greater than 100 kV. Regarding the responsibilities assigned to the Transmission Planner in the draft standard, the SDT believes standard language lines up well with the vast majority of entity business practices in effect regarding the interactions between generation and transmission entities when collaborating on generator dynamic models. Since ERCOT is an exception, a regional variance should be considered. Alternatively, the Transmission Planner could delegate the responsibility to another such as its Planning Authority.**		
Exelon	Yes	Requirement R2Exelon is in agreement that the Generator Owner (GO) should provide the generator excitation control system and plant volt/var control model and any necessary input data; however, the Transmission Planner (TP) should be the entity that is responsible for the model verification. Transmission Planning organizations have the expertise to implement and test the models in software, while the GOs have the necessary access to the equipment in the field. Most GOs do not have the software and the necessary personnel with the expertise to perform the modeling and model testing required by this draft Standard. Typically, TPs currently have existing software programs to run the excitation system models. The overall quality of the verification would be best served by having the TP that has knowledge in the model performance verse the GOs that do not have the current expertise in model performance or

Organization	Yes or No	Question 4 Comment
		dynamic system response evaluations.Exelon also believes that the Standard should specifically define the acceptance criteria. If the acceptance criteria are left up to the GOs, then the TOs may have to deal with multiple acceptance criteria within a single Region. At the same time, a single GO may have to work with multiple TOs, which will lead to inconsistency if definition of the acceptance criteria is left up to the TO.Requirement 2.1.1The Standard needs to provide specific guidance as to what criteria a voltage excursion from either a staged test or a measured system disturbance should be in regards to performing the verification. In addition, the SDT should provide specific examples of what types of staged tests would be considered acceptable. It is difficult to comment on the potential impact to the generating units (especially a nuclear generating unit) without knowing the criteria.

Response: The SDT thanks you for your comment.

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 Transmission Planner has expertise in overall power system simulation analysis but not necessarily expertise in specific excitation control system modeling. While the Transmission Planner can continue to participate in model verification to whatever extent agreements with the generator entity stipulates, the majority of the SDT and industry, based upon comments received, believes that the Generator Owner should be responsible for this activity. Also, 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 excitation system model response matches the response from a recorded voltage excursion. This can be accomplished through software that is much simpler than full dynamic simulation software utilized by Transmission Planners for assessing BES limits. If the Generator Owner determines that it does not want to develop in-house expertise to perform model verification activities, it can choose to hire consultants or continue any arrangements with its Transmission Planner to completely or partially provide this service as required once every ten years – though the task would be delegated, the Generator Owner would ultimately be responsible for compliance with the applicable Requirements.

Regarding the second half of the comment beginning with a desire for acceptance criteria, the standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.

Dynegy Inc.	Yes	R2.1.1 does not specify the magnitude of the required voltage excursion, i.e. 1%, 2%, etc. Is their a

Organization	Yes or No	Question 4 Comment
		specific required voltage change level?
Response: The SDT thanks you for your comment. No, the standard does not specify a required voltage change level. The SDT drafted a Standard that states "what is required", not "how to accomplish what is required".		
Austin Energy	Yes	ERCOT performs computer modeling based data (RARF) provided by Generators. Please consider allowing an exemption or alternate methods for older unit dynamic data as the information for these older units is not always available. ERCOT has used typical or generic modeling parameters for these units.
Response: The SDT thanks you for your comment. The model can still be verified even if existing dynamic data for older units submitted per the Requirements of MOD-012 and MOD-013 represent typical or generic data.		
Independent Electricity System Operator	Yes	1. We do not agree with some of the requirements.i. R1: Standards should stipulate the "what's" not the "how's". To avoid the perception that the requirement is prescribing the "how", we suggest simplifying the language of Requirement R1 by replacing "Instruction on how to obtain" with "Instructions for obtaining".Further, are all three bullets meant to be complied with or are they listed as options? We understand that the general rule for NERC standards is that those items that must be complied with are labeled as parts (e.g. 1.1, 1.2, etc.) while those that are options or examples that do not need to be complied with are placed in bullets. Please verify this with the Director of Standards Process.ii. R2.1: The phrase "models acceptable to its Transmission Planner" begs the question on what is deemed acceptable and what if the GO disagrees with the TP's determination. To address the two issues, we suggest adding a requirement for the TP to specify the models requirements (or change the second bullet in R1 to achieve this), and change the wording in R2.1 to "in accordance with the models specified by the TP (or referencing the requirement part that contains the specification). 2).iii. We are not sure why Requirement R5 is needed. First of all, it suggests that a Planning Coordinator may request the GO to perform a model review where the request can be technically justified. We wonder if the requirement really means "Transmission Planner" rather than "Planning Coordinator" since TP as the requester and model user is specified throughout the standard. Secondly, if it is indeed TP that was meant to be the requester, then would this request already been covered by Requirement R3? If not, what are the technical justifications? They are not specified in R5, unlike its R3 counterpart. Please clarify and/or revise the requirement as appropriate.iv. 3) R6 stipulates the criteria that may not be accomplished even if the GO provides an accurate excitation control system and plant volt/var control function model. A computer model may fail to initialize due to reasons other than the submitted excitation control system and plant volt/var control function model itself;

Organization	Yes or No	Question 4 Comment
		a no-disturbance simulation may not result in negligible transients due to other reasons; and finally, a disturbance simulation may not result in the excitation control system and plant volt/var control system model exhibiting positive damping due to other system parameters. 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 excitation control system and plant volt/var control function model does not necessary guarantee or equate to meeting the conditions stipulated in the three sub-requirements. We suggest this requirement be removed. Further, in many jurisdictions the setting and tuning of excitation control systems and associated power system stabilizers, etc. are determined by the Transmission Planners (or Planning Coordinators); the GOs would simply provide the equipment and set them according to the TP's specification. In this standard, the responsibility is for the GO to verify that the model reflects the actual response of the tested equipment, whose settings have been determined prior by the other responsible entity.2. 4) In the previous posting, we provided 2 comments which in our view, have not been duly and satisfactorily addressed by the SDT and we would like to reiterate them here:i. We suggested that at a minimum, the generator's basic characteristics such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), voltage regulators, turbine-governor systems, etc. as stipulated in MOD-013 that support modeling for dynamic simulations should also be verified. A good excitation system model without a valid generator model will not provide the assurance that the simulation results are valid, which may hurt reliability.In response to this comment, the SDT indicates that: "[it] agrees that appropriate dynamic models are needed for generators, exciters, PSS, and governors. The SDT believes that when testing personnel verify the excitation system model data, they also provide verification of the generator model data. A match between simulation and measured results for the excitation system model is required to indicate that the generator and excitation control system models accurately represent the equipment. The governor model is not verified with the excitation system model since it requires a frequency excursion. Verification of the governor model will be addressed by the MOD-027 standard. Experience indicates verification required by the MOD-026 standard often results in discovery of significant changes to the representation of the generator and exciter, suggesting that model verification provides significant reliability improvement."Generator model parameters need to be verified based on tests conducted during both turbine/governor model verification as well as excitation system model verification. We are however not convinced that those tests that need to be performed during the excitation system model and data verification process, to verify certain portions of the generator model parameters will be conducted as a matter of course. We therefore reiterate our view that the verification of generation model parameters needs to be included within the scope of this standard and we urge the SDT to consider our comments again.ii. 5) We suggested that in some areas on the interconnection, such as those that are sparsely populated,

Organization	Yes or No	Question 4 Comment
		performance of generating units at less than 100 MVA might be critical to reliability. The criteria to allow the TP and PC to identify these units could include: a. A 5% or 10% deviation of any or several of the excitation system's parameters/settings could make an otherwise stable simulation to be unstable; b. Use of generic models for the excitation system or generator would make an otherwise stable simulation to be unstable. c. Other changes or incorrect assumptions for the excitation system or generator would make an otherwise stable simulation to be unstable. The SDT responded that: "After reviewing provided details, the SDT encourages you to review the new process draft (reference Requirement R2) and provide additional comments as appropriate." Requirement R2 does not contain any provision that a TP (or PC) can request for model verification of units that do not meet the Applicability criteria. Throughout the standards, such a provision does not exist. This could leave room for system to exhibit unstable performance for reasons indicated in our previous comments. We urge the SDT to reconsider our proposal.

Response: The SDT thanks you for your comment.

1) Requirement 1 does describe the "what". The "what" is that upon request, the Transmission Planner is to provide the Generator Owner data or instructions on how to obtain needed information. As stated in requirement 1, the three bullets identify instructions and data the Generator Owner can request from the Transmission Planner. The Transmission Planner is only required to provide information requested. The SDT believes standard formatting is correct since the Generator Owner determines what, if any of the information identified is requested from the Transmission Planner.

2) Response: Several commenters expressed concern with the new Requirement 5 added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review. Conversely, Requirement 3 only applies to units in the base Applicability (a subset of units identified the NERC Registry Criteria). This requirement is assigned to the Planning Coordinator to address generator owner concern that the transmission planner might request a model review without proper justification. The requirement is written to require a higher level of justification for requesting a model review than simply contacting the generator owner.

3) Response: R6.1, R6.2, and R6.3 represent established industry practice for assuring model usability. The positive damping requirement makes the generator owner provide a response if a new model introduces negative damping. This requirement recognizes that the equipment must be positively damped during actual operation. Negative damping occurring during simulation indicates incorrect modeling. Initialization errors and oscillation transients without disturbance conditions also indicate incorrect modeling.

4) Response: The SDT agrees generator parameters such as the inertia constant, damping coefficient, saturation parameters, direct & quadrature axe reactance's, and time constants need to be correctly modeled. Since the phrase, "excitation control system" is an IEEE defined term with specific

Organization	Yes or No	Question 4 Comment
meaning; the SDT contends this term incorporates the generation model parameters by definition. The generation model parameters must be correct to successfully verify the excitation control system model. Note that the governor turbine model verification is addressed by the MOD-027 standard. The SDT recognizes the various control systems interact and expects correct modeling data. The purpose of this standard is model verification and not the development of correct modeling parameters. If model verification is not successful, then the modeling parameters are not correct and the generator owner will need to identify and correct bad parameters. This standard intentionally avoids specifying how to correct model parameters with expectation the generator owner demonstrates that model data is correct. **5) The SDT regrets that the provided Reference number in the last Consideration of Comments response was incorrect. The SDT added language to the draft standard in Requirement 5 after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) if technical justification demonstrates the simulated unit response does not match the measured unit response. This will include units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) but are less than the standard's base Applicability (including units > 100MVA for the Eastern Interconnection). In summary, Requirement 5 allows Planning Coordinators to request additional model information, which could include model verification, for units less than 100 MVA that are critical to reliability and have shown that their model does not accurately predict actual equipment response.**		
Wisconsin Electric	Yes	Section A Effective Dates: In 5.2.1, replace "30% of its applicable units" with "20% of its applicable units". There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years.Section B: Requirement R1: Replace "Each TP shall provide the following INSTRUCTIONS AND DATA to its GO..." with "Each TP shall provide the following DATA to its GO...". On the first two bullets, remove the phrase "Instructions on how to obtain..." The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace "Any of the GO's existing ... model data" with "All the GO's existing ... model data...". Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, "Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models..." The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3.In R2.1.1, replace "Documentation demonstrating the ... model response matches the recorded response" with "Documentation WHICH MAY BE USED TO DEMONSTRATE that the ... model response matches the recorded response". In R2.1.3, 2.1.4, and 2.1.6 replace "model structure" with "block diagram". In Requirement R3, replace "90 calendar days" with "180 calendar days", to allow more time to work through the technical challenges relating to these models.In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace "walk down" with "inspection". Comments on Attachment 1:1. Remove the note which says, "Note that local grid codes may specify...".2. Under "Conditions" for existing generators, it is not clear why there are references to both a ten year period and an eleven year period. Also, replace "Subjected to an activity resulting in an alteration of the response of the excitation control system" with "Changes to control system or parameter values".3. Under the

Organization	Yes or No	Question 4 Comment
		exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under "Periodicity" for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis.Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.

Response: The SDT thanks you for your comment.

1. **The SDT considered industry concerns provided in response to the first posting of the standard for this issue and decided to revise the timeframe following standard approval for the first set of models required to be verified from "after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis" to "…four years following applicable regulatory approval….Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R1." In addition to allowing entities additional start up time to develop this expertise, the revised timeline enables traditional staged testing to be performed concurrent with a scheduled planned maintenance outage. The SDT believes this change allows adequate time for entities to perform model verification activities.**
2. **The SDT believes it is necessary to provide instructions for obtaining the data since a) the SDT anticipates most entities will post the "acceptable list of models" on a website, and b) providing instructions on how to obtain block diagrams or data sheets will help ensure vendor dynamic simulation software data sheets are legally obtained.**
3. **It is acceptable for a Generator Owner to request information for any of its units or plant excitation control systems.**
4. **Requirements R6.1 through R6.3 specifies how a Transmission Planner determines if the model is usable. This determination should not be confused with verifying the model response matches actual equipment response. A model is not considered "usable" if angle drift occurs without a disturbance condition present or if poorly damped oscillations occur when disturbance conditions exist. As required by R2, model verification is ensuring that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event).**
5. **The phrase "may be used" would undermine the primary reliability related intent of the standard which is to ensure that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event). Also, the SDT intends to keep the phrase "model structure" since a model structure is a block diagram without parameter values.**
6. **Requirement R3 does not require the Generator Owner to verify the model. Allowing more than 90 days only prolongs the dialog.**

Organization	Yes or No	Question 4 Comment
7. Requirement R5 does not require the Generator Owner to verify the model. Allowing more than 90 days prolongs the process of updating the model which the Planning Coordinator needs to have revised so that accurate BES stability limits can be calculated. The SDT regrets that it could not find the reference to "walk down". **8. Regarding the first two Attachment 1 comments, the Attachment has been revised.** **9. Regarding your Attachment 1 comment pertaining to allowable MVA size, the SDT responded to industry comments by raising the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA threshold is critical to BES reliability and should have the excitation control system model verified at least once each decade.** **10. Regarding your second to last Attachment 1 comment, the SDT believes that if any control changes are implemented, they would be performed at the same time a staged testing is conducted (for example, adjusting gain based on the results of a step change voltage test).** **11. Regarding your final Attachment 1 comment, the SDT expects either traditional staged testing or ambient monitoring will be used to collect data for model validation. As such, there is not a need to provide additional incentive to the TO/TOP.**		
We Energies	Yes	Section A Effective Dates: In 5.2.1, replace "30% of its applicable units" with "20% of its applicable units". There will be a substantial learning curve with this new requirement, therefore the requirements should be less demanding in the earlier years. Section B: Requirement R1: Replace "Each TP shall provide the following INSTRUCTIONS AND DATA to its GO..." with "Each TP shall provide the following DATA to its GO...". On the first two bullets, remove the phrase "Instructions on how to obtain..." The TP should simply provide this data, and not merely the instructions on how to get it. On the third bullet, replace "Any of the GO's existing ... model data" with "All the GO's existing ... model data...". Since the TP already has this data, it is more straightforward to simply provide all relevant data to the GO. Requirement R2: Replace the first sentence with, "Each GO shall provide data which MAY BE USED TO VERIFY the generator excitation control system and plant volt/var control models..." The verification of these models is not determined by the GO, but by the TP in Requirement R6, R6.1, R6.2, and R6.3. In R2.1.1, replace "Documentation demonstrating the ... model response matches the recorded response" with "Documentation WHICH MAY BE USED TO DEMONSTRATE that the ... model response matches the recorded response". In R2.1.3, 2.1.4, and 2.1.6 replace "model structure" with "block diagram". In Requirement R3, replace "90 calendar days" with "180 calendar days", to allow more time to work through the technical challenges relating to these models. In Requirement R5: Allow 180 days for a response to the PC for the reasons above. This will allow time in the event that the request from the PC lacks the technical rationale or details that are required. Also, in R.5.2, replace "walk down" with "inspection". Comments on Attachment 1: 1. Remove the note which says, "Note that local grid codes may specify...". 2. Under "Conditions" for existing generators, it is not clear why there are

Organization	Yes or No	Question 4 Comment
		references to both a ten year period and an eleven year period. Also, replace "Subjected to an activity resulting in an alteration of the response of the excitation control system" with "Changes to control system or parameter values". 3. Under the exceptions for existing generators, the allowable MVA size should be increased to 500 MVA. 4. Under "Periodicity" for existing generators, in the last three rows covering situations where the recorded response did not match the predicted response, where the PC requests a review, and where the model is identified by the TP as unusable, the GO should be allowed two years (instead of one year) to provide a recorded response for a voltage excursion due to the possible need to take the unit out of service to make control changes, especially where outages are not scheduled on an annual basis. Lastly, staged testing for generator exciter model verification will likely require switching of lines on the transmission system. In cases where the Generator Owner does not own or operate the transmission system, the TO or TOP may understandably be reluctant to switch lines out due to reliability concerns. For this reason, R2 should be modified to provide more incentive for the TO/TOP to coordinate with the GO to do the required testing.

Response: The SDT thanks you for your comment.

1. **The SDT considered industry concerns provided in response to the first posting of the standard for this issue and decided to revise the timeframe following standard approval for the first set of models required to be verified from "after 2 years of regulatory approval, 10% of its applicable units per Interconnection on a MVA basis" to "…four years following applicable regulatory approval….Each Generator Owner shall ensure at least 30% of its applicable units per Interconnection on an MVA basis are compliant with Requirement R1." In addition to allowing entities additional start up time to develop this expertise, the revised timeline enables traditional staged testing to be performed concurrent with a scheduled planned maintenance outage. The SDT believes this change allows adequate time for entities to perform model verification activities.**
2. **The SDT believes it is necessary to provide instructions for obtaining the data since a) the SDT anticipates most entities will post the "acceptable list of models" on a website, and b) providing instructions on how to obtain block diagrams or data sheets will help ensure vendor dynamic simulation software data sheets are legally obtained.**
3. **It is acceptable for a Generator Owner to request information for any of its units or plant excitation control systems.**
4. **Requirements R6.1 through R6.3 specifies how a Transmission Planner determines if the model is usable. This determination should not be confused with verifying the model response matches actual equipment response. A model is not considered "usable" if angle drift occurs without a disturbance condition present or if poorly damped oscillations occur when disturbance conditions exist. As required by R2, model verification is ensuring that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event).**
5. **The phrase "may be used" would undermine the primary reliability related intent of the standard which is to ensure that the predicted model response matches the actual equipment recorded response for a voltage excursion from either a staged test or a measured disturbance (ambient event). Also, the SDT intends to keep the phrase "model structure" since a model structure is a block diagram without parameter**

Organization	Yes or No	Question 4 Comment
		values. **6. Requirement R3 does not require the Generator Owner to verify the model. Allowing more than 90 days only prolongs the dialog.** **7. Requirement R5 does not require the Generator Owner to verify the model. Allowing more than 90 days prolongs the process of updating the model which the Planning Coordinator needs to have revised so that accurate BES stability limits can be calculated. The SDT regrets that it could not find the reference to "walk down".** **8. Regarding the first two Attachment 1 comments, the Attachment has been revised.** **9. Regarding your Attachment 1 comment pertaining to allowable MVA size, the SDT responded to industry comments by raising the MVA threshold for "proxy" units from 250 MVA to 350 MVA to ensure that steam units at sites with multiple combined cycle plants are included. The SDT believes that units rated above the 350 MVA threshold is critical to BES reliability and should have the excitation control system model verified at least once each decade.** **10. Regarding your second to last Attachment 1 comment, the SDT believes that if any control changes are implemented, they would be performed at the same time a staged testing is conducted (for example, adjusting gain based on the results of a step change voltage test).** **11. Regarding your final Attachment 1 comment, the SDT expects either traditional staged testing or ambient monitoring will be used to collect data for model validation. As such, there is not need to provide additional incentive to the TO/TOP.**
Great River Energy	Yes	We appreciate the drafting team's consideration in Section A.6 to allow a unit that has already verified its excitation system to be considered compliant. However, it is not clear how this section helps. How does the Generator Operator demonstrate that it is already compliant when it was not required to retain documentation? Will an attestation by appropriate level of staff besufficient? Will the regional entities be willing to validate that they have confirmed regional criteria?This standard is overly administrative by memorializing the interactions between the Generator Operator, Transmission Planner and Planning Coordinator that occur to model the generator's excitation system. Specifically R1, R3, R4 and R5 should be struck. They are purely administrative and present compliance risk to the registered owners without commensurate reliability benefit. For Requirement R6, the portion requiring a written response should be struck as well. Only two requirements are needed to accomplish the purpose of this standard. They are: ne requirement for theGenerator Operator to perform the test and one for the Transmission Planner to verify the model is accurate.Requirement R6 creates a situation where a Transmission Planner could be forced to decide between living with an exciter model that needs adjustment and violating the standard. Upon initial examination, the Transmission Planner may determine that the model meets Parts 6.1 through 6.3. Only after months or years of extensive study, it is possible that the Transmission Planner determines that the excitation model could stand some improvements. If they submit a written response one year later, the Transmission Planner may be in violation of Requirement R6. This just represents one of the issues with

Organization	Yes or No	Question 4 Comment
		memorializing the interactions between the Transmission Planner, Planning Coordinator and Generator Operator in the standards.Because the tests to verify the excitation model can be expensive, there should be a demonstrated need to perform a test. Summaries of field test results posted with the second draft of the SAR indicate the costs of these tests could range from $5,000 to $50,000 for a single unit. That does not even include opportunity costs from lost energy sales should the test cause the unit to trip. Thus, if there are no demonstrated modeling deficiencies (i.e. benchmarking reveals model results do not align with actual system results), then no test should be required and the generator operator should be able to wait for a system disturbance appropriate enough to verify its model.Because R3 and R5 give only 90 days to respond to the Planning Coordinator's and Transmission Planner's issues with the excitation model, these requirements could compel tests during a seasonal peak time frame. At a minimum, the Generator Operator should have 180 days to perform the test if that is what is identified as its response to avoid jeopardizing unit tripping during periods of high loads.

Response: The SDT thanks you for your comment.

1. **It is beyond the scope of the SDT to specify how an entity will provide evidence if requested to verify a model compliant with the applicable regional entity polices, guidelines, or criteria. It is hoped that documentation and/or correspondence created during the model verification process was compliant with regional entity policies, guidelines, or criteria and maintained by the Generator Owner for use as evidence. The decision to attest or validate regional criteria will have to be determined by the respective region.**
2. **Regarding your comment suggesting that R1 should be struck, the SDT cannot draft a Requirement for a Functional Model Entity without assurance that they have the proper information to satisfy the Requirement. R1 is necessary to ensure the Generator Owner has the proper information to comply with R2.**
3. **Regarding your comment suggesting that R3, R4, and R5 should be struck, the SDT acknowledges that these Requirements are "exception type" Requirements that should rarely be used however the SDT believes striking them from the standard would be detrimental to reliability. Without these Requirements, model accuracy issues may not be resolved for ten years.**
4. **Regarding the comment addressing Requirement 6 language, the Requirement references usability testing only which can be readily completed by the Transmission Planner. R6 language does not prevent the Transmission Planner from requesting the Generator Owner to verify information if there is evidence that the model is incorrect. The third bullet of R3 mandates that the Generator Owner must respond to evidence from the Transmission Planner that the modeled response does not match the recorded response and this language allows the Transmission Planner, assuming supporting evidence is available, to request a review at any time..**
5. **Regarding your comment about the need for model verification, the SDT has proposed unique MVA thresholds for each Interconnection that correspond to 80% of the Interconnected MVA, which represents a subset of the units identified in the NERC Registry Criteria. This philosophy was adopted because of the standard Phase III-IV NERC Field Test results obtained. While Field Test results confirmed that verification of excitation system models resulted in higher quality dynamic data, it was also confirmed that excitation system model verification is expensive and requires a significant amount of manpower to accomplish. The SDT believes that the applicability MVA thresholds established will**

Organization	Yes or No	Question 4 Comment
improvement excitation model accuracy, including Reliability, in both a cost effective and manpower effective manner. **6. Regarding your last comment, please note that the Requirements R3 and R5 only require the Generator Owner to respond to the Transmission Planner within 90 days, and that response could be a plan to verify the model. Once this response is provided, the Generator Owner has one year to collect a voltage excursion and another 180 days to complete model verification based on the current language of Attachment 1.**		
Duke Energy	Yes	1) If System Models are poor today, it is probably due to a lack of understanding on what models are required, setpoint control and what changes need to be communicated to Transmission when plant projects are done. Periodic reverifications are probably not the right way to ensure reliability. Instead there should be an event-based revalidation requirement, such as if you replace the control system or recalibrate the control settings on an existing unit, replace the rotating exciter or rewind a generator. An approach where there is an initial validation effort to get today's models consistent with installed equipment is clearly needed. However, assurance that future models will remain valid requires that there is a program in plant project processes to revalidate when appropriate, and thus a requirement to show that the company has the needed project processes and has followed that process is the right way to approach this.2) There needs to be a requirement for the entity responsible for actually inputting the models and data to do so on a timely basis. This should be an annual update of data to be submitted to the interconnected models. As currently written, there is a requirement for the GO/GOP to submit information, but they do not input directly into the interconnected system models. MOD-010, MOD-011, MOD-012 and Mod-013 don't currently ensure that data is incorporated in a timely fashion.3) Since GO/GOPs do not always have electrical system modeling expertise, nor participate in interconnected system models groups such as the MMWG which sometimes changes how equipment is modeled, there probably needs to be a guide that clearly identifies the steps a GO/GOP needs to take to maintain models up to date. The NATF and EPRI/NAGF are considering a collaboration to do so.4) Identically designed generation units are identical in control response, independent of site location. New techniques for validation eliminate the impact of the grid on the validation efforts. Thus, credit for sister unit validations should be available independent of the location of a unit.5) Discussions during the EPRI PPPD users group indicate certain parameters in the models are temperature sensitive, and thus verification and adjustment of models should be done under conditions that reflect normal operating conditions. An on-line voltage step test or DFR data from an event is the best way to perform the validations. It's not clear if validations against off line tests would actually make the models worse, but the industry should be encouraged to do validations on line near full power.6) R2, 2.1.3 Total unit inertia should be given to include all coupled rotating elements. The way this is currently worded, it could lead generators to only provide the generator H values.7) Footnote 4 - Delete the phrase "or evidence that the simulated unit or plant response does not match measured unit or plant response". Otherwise this standard could be made applicable to a small unit that has no impact on reliability.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. **1. The philosophy adopted for the draft standard is based on recently completed NERC sponsored Field Testing. Field Test results confirm excitation system model verification results in higher quality dynamic data. Since excitation system verification is costly and requires significant manpower, the SDT believes the applicability should be a subset of the NERC Registry Criteria and a ten year verification periodicity is appropriate for reliability. Also, the standard includes "event-based" validation requirements to ensure that the model is verified when issues are discovered (Requirement 3, third bullet).** **2. The results of model verification are required to be transmitted to the Transmission Planner per Requirement 2 and Attachment 1. Sufficient time is provided for the Generator Owner to verify the equipment response matches the predicted response. While the SAR for MOD-026 addresses model verification, which the SDT believes includes the transmittal requirements specified in Attachment 1; it does not address the data submission requirements of MOD-010 and MOD–012.** **3. Regarding the third comment, the SDT agrees development of model verification guides by credible industry groups such as the NATF and EPRI is a worthy endeavor.** **4. Regarding the fourth comment, the SDT respectfully asserts that the "same physical location" requirement is necessary since this language provides a strong indication of equipment and settings similarity (which can be verified by the same field personnel during a single site walk down). For example, a GO/GOP could own/operate otherwise similar equipment physically located in different geographic locations or regions with different operating procedures/requirements (e.g. having the PSS in-service). To ensure all GO/GOP equipment meets standard intent, the SDT maintains the "same physical location" requirement is necessary.** **5. Regarding the fifth comment, the SDT maintains that the standard should state "what is required" and not specify "how to perform what is required". The SDT refrains from entering the debate because both the online and offline step change voltage tests and the ambient event test are adequate for performing model verification.** **6. Regarding the sixth comment, the SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.** **7. Regarding the last comment, several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review.**		

Organization	Yes or No	Question 4 Comment
Western Electricity Coordinating Council	Yes	Requirement R1, first bullet. Grammatically, should the word model in the first bullet be models?Requirement R4 requires the Generator Owner to provide revised model data or plans to perform model verification. The way I interprete the wording of Requirement 4 is that the model data or plans to perform model verification are due within 180 calendar days. If the GO provides plans to perform model verification and submits the information on their plans within 180 days, is there any time limit as to when the model verification must be performed? If so I suggest it should be included in the language of the Requirement. If the actual verificatio must be done within 180 days this should be clarified becasue right now it just looks like only the plans have to be submitted within 180 days.
Response: The SDT thanks you for your comment. **1. Regarding the first comment, the SDT has corrected the error in R1.** **2. Regarding the second comment, the Generator Owner has 180 days to respond, and that response could be a plan to perform model verification. If the Generator Owner plans to perform model verification, then footnote 5 specifies that the ten year periodicity would be reset as detailed in Attachment 1. More specifically, once the Generator Owner states an intention to re-verify the model, Attachment 1 allows up to 365 days to record and collect an ESC response and then is allowed up to 180 days to transmit the verified model and documentation to the Transmission Planner.**		
ISO New England Inc.	Yes	1) This standard may lead Generator Owners to violate another NERC Standard; this standard implies in requirement R4 along with footnote 6 that Generator Owners could have 180 days to notify its Transmission Planner that an AVR status has changed. The VAR standards require notification within 30 minutes of a change in AVR status.Requirement R4 is also a direct violation of the ISO/FERC Tariff Section I.3.9 that requires generators to provide information prior to making material changes to equipment characteristics. Allowing generators to make changes such as these without prior review represents a significant reliability concern. 2) MOD 26 needs to clearly state that non-proprietary models need to be provided by Generator Owners, otherwise a major reason (NERC MMG) for model collection will be undermined.As written, the intent of requirement R2.1.1 is unclear. 3) How are stabilizers and excitation limiters to be addressed? How large does the voltage excursion need to be? This requirement needs to be made much more specific. 4) With respect to requirement R1, the standard should allow user models to be provided. The second bullet point implies that models would only be allowed from a list of standard models. User written models

Organization	Yes or No	Question 4 Comment
		may provide more accurate representations of actual equipment installations. However, these models cannot be proprietary and must be able to be distributed.In requirement R5.2 bullet 1 - generator owners should not be providing generic model data. In requirement R5.2 bullet 2 - what constitutes a "walk down" of the equipment? 5) Suggest replacing with "Updating parameters based on actual field verification of equipment settings."This standard should indicate what constitutes the excitation system and should indicate that it includes a power system stabilizer and limiters. 6) This standard addresses existing generators, but should also address new generators.In regard to the Effective Dates: How is this to be implemented? GOs may have units in multiple control areas. TOs may be in multiple areas. This seems impossible to track and may leave some areas with very little verification for up to ten years after the standard has been approved. The Planning Coordinator should be given the discretion to require and approve a test schedule within it's area.

Response: The SDT thanks you for your comment.

1) The requirements of MOD-026 do not usurp the requirements of other standards. Providing notification of AVR status change is not the same as verifying model data following equipment status change that may affect the model. MOD-026 requires model verification and this cannot be performed until after equipment changes occur and the generator is operating. Also, MOD-026 addresses verification of ECS models that are in service. MOD-026 does not alter requirements for preliminary model data as specified by any Tariffs.

2) Requiring Generator Owners provide models based on an acceptable model list provided by the Transmission Planner is intended to establish usable models. Part of this intention is to address the necessity for non-proprietary models.

3) Generator owners are expected to provide correct stabilizer and excitation limiter data. MOD-026 requires verification of the complete model but does not verify every detail of the model. Limits are difficult to verify using staged or ambient tests. The generator owner and subject matter experts have to determine how to develop correct data.

4) The standard does not prevent user models however the model must be on the list approved by the Transmission Planner. An equipment "walk down" to correct model parameters could be as simple as identifying by observation in the field that equipment gain or limit setting values are incorrectly represented in the model.

5) The standard uses the IEEE term "excitation control system" which includes the PSS, limiters, and generator. The standard requires verification that model data matches equipment performance for the complete voltage control system.

6) The SDT addressed new equipment in Attachment 1 and provided 180 days to complete model verification. Generator owners are required by other standards to provide correct model data so the SDT believes the implementation time frame allows sufficient time to adequately verify the model without impacting Generator Owner ability to develop capabilities and verify models for their other units.

Organization	Yes or No	Question 4 Comment
Ingleside Cogeneration LP	Yes	MOD-026-1 already takes Ingleside Cogeneration LP out of its comfort zone by requiring the ownership and validation of interconnected system performance simulations. This is normally a Transmission Planner or Transmission Operator function, not a Generator Owner. Although we understand the benefit of modeling validations, it is appropriate to begin with only the most critical facilities.If anything, we believe the applicability criteria should be consistent with those generation facilities which have DME installed as required by their Regional Entity. This is a reasonable, in-place means to identify those generators which are important to BES voltage response - and have already the recording equipment needed to validate performance.
Response: The SDT thanks you for your comment. The SDT believes that the Generator Owner is in the best position to determine realistic and reasonable model representation of installed equipment. For this reason, the standard gives the Generator Owner authority to determine if the model adequately represents performance of installed equipment. It is not desirable to link this standard with the DME standard under development. Also, the DME standard applies to fault recorders and PMU equipment. Low resolution data is adequate for verification. The SDT agrees that if DME is already in place, especially if it is monitoring the appropriate quantities required for excitation control system verification, then it should be simpler to capture the required data for verification. The applicability section requires verification of units larger than the MVA threshold gross nameplate rating specified for each interconnection and this threshold is intended to emphasize the importance of modeling critical units.		
Southern California Edison Company	Yes	SCE believes that the Section 4.2.4 of the Applicability Section should be revised to read "Any technically justified unit requested by the Transmission Planner." We believe that the Transmission Planner is the appropriate functional entity for this role.In addition, SCE believes that Requirement 1 should be revised to allow the Transmission Planner a full 60 days in which to provide the information to the Generator Owner. At various times, Transmission Planners may be inundated with such requests from Generator Owners and may require the extra time in which to respond.
Response: The SDT thanks you for your comment. In response to your first comment, the second posting of the standard has proposed a process where the Planning Coordinator can request a review of an excitation control system model for a unit not specified in the standard Applicability section. This requirement was added by the SDT in response to industry asking if a transmission entity should be allowed to identify additional units beyond those identified in the base Applicability. The base Applicability, though expanded in this posting, continues to be a subset of units identified by the NERC Compliance Registry. Also, the time period in Requirement 1 has been increased to 90 days to match the time period in the VSL.		
Ameren	Yes	Our comments/concerns are : 1)The wording for Requirement 2.1.4 should be changed to read “Model structure and data for the excitation system, for the plant volt/var system, and for the closed loop voltage regulator”. Otherwise, as written, it appears that the required model structure and data only applies to the voltage regulator portion of the equipment.2)In Requirement R5, the term “technically justified request” needs to be clarified. 3)In Requirement R2.1.3, it should be clarified that “rotational inertia” should include

Organization	Yes or No	Question 4 Comment
		all rotational mass connected to the generator shaft, rather than only the rotational inertia of the generator itself.4)Units rated 20 MVA will not have a significant impact on system reliability. Only units and aggregate plants capable of > 100 MVA should be included.5)Sister unit exemptions should be allowed where there is a solid technical support for units built and operated as virtually indistinguishable generators.6)The SDT should review the requirements in this draft to ensure they do not overlap the requirements in MOD-012 and MOD-013. From our read it appears generator owners will be at serious risk for double jeopardy.7)The draft uses the term "Point of Interconnection" in several locations, especially R2.1.1. This is not a NERC Glossary term, although the Team used footnote 3 as an internal definition.8)Footnote 6 should be a set of sub-requirements for R4.9)Section 6 should be part of the Implementation Plan since it deals with the initial phase-in of the Standard.10)Footnote 2 should probably be in the Applicability Section, but should not stay as a footnote - it's too important in determining which generators must comply.
Response: The SDT thanks you for your comment. 1) The SDT has revised R2.1.4 incorporating the essence of your suggestion. **2) The SDT has revised Requirement R5 using a footnote to define the phrase, "technically justified" as the simulated unit or plant response does not match measured unit or plant response.** **3) The SDT believes that the term rotational inertia is well understood in industry. The term "rotational" infers a mass that is attached to the unit shaft.** **(4) The SDT is only proposing verification of units rated 20 MVA at plants which exceed the interconnection established MVA threshold (which is 100 MVA for the Eastern Interconnection). Even with the MVA threshold satisfied, units satisfying sister/proxy unit criteria will not have to be verified, further reducing the number of units actually tested.** **(5) The SDT believes sister/proxy unit criteria established is adequate.** **(6) MOD-012 and MOD-013 requires submission of the latest equipment dynamic model data. MOD-026 requires verification of the equipment dynamic model data.** **(7) Your observation regarding the phrase "point of interconnection" is correct. Please note that this phrase is not capitalized in the standard.** **(8) The SDT believes providing the list associated with Footnote 6 in the Requirement section would make the standard cumbersome to read.** **(9) The SDT believes that Section 6, since it addresses early compliance considerations, is important to require its own "section" in the standard.** **(10) The SDT believes providing the list associated with Footnote 2 in the main body of the standard would make the standard cumbersome to read.**		
American Electric Power	Yes	Standard models may not be available for wind units and wind facilities (which appear to be within scope), particularly aggregate reactive and frequency response controls at the farm level. As a result, it might be difficult to obtain and provide such information.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comment. Generic models are available and there are efforts, as detailed in the Background Information associated with this posting, that are expected to result in more robust models. Requirement R2.1.1 states that the Generator Owner is required to produce documentation demonstrating the unit or plant's model response matches the recorded response for a voltage excursion at the generator or plant point of interconnection from either a staged test or a measured system disturbance. Since the Generator Owner has the final say in determining if the match is adequate or not, to the extent that non-proprietary models can be used to "match" the recorded response from the actual equipment, then that will be sufficient for compliance with the Requirements.		
Texas Reliability Entity	Yes	(1) The implementation period in this standard is far too long. It is unreasonable to allow 11 years for a GO to provide a verified model for 50% of its generation capacity. All generation should comply with Requirement 2 within 3-5 years.(2) The periods allowed for providing correction of identified model deficiencies and updates for system changes are too long. It appears (from Attachment 1) that a GO has almost 2 years to provide a corrected verified model after a request from a TP or an equipment change (per Requirements R3, R4 and R5). This work should be completed within one year to ensure accurate system modeling.(3) It is unclear exactly what is required by Attachment 1, and how the material in the attachment relates to the Requirements. The Attachment appears to contain additional requirements. We suggest moving the required actions described in Attachment 1 into the applicable Requirements, such as the requirements and time periods for recording responses and providing new information to the TP. (4) It is unclear what the 10 and 11 year periods/cycles referenced in the first two rows of Attachment 1 refer to. This needs to be clearly explained somewhere.(5) It is our understanding that this standard is intended to require re-verification of models at least every 10 years, but there is no requirement that clearly sets forth any re-verification requirement or period. (6) Requirement 6 requires the TP to determine if a model is "usable" based only on whether the model is functional, omitting any consideration of whether the model is reasonably accurate. An incorrect model could satisfy 6.1, 6.2 and 6.3. We suggest adding an R6.4 relating to whether the model is reasonably accurate, i.e., whether it reflects actual unit performance.(7) In 4.2.3, in the first bullet, "with rating greater than" should be changed to "at greater than," which is clearer and consistent with the parallel descriptions in neighboring sections.(8) In the "Consideration for Early Compliance" section, first bullet, "applicable regional entity policies" should be changed to "applicable region policies." In our region, and perhaps others, there are applicable policies, but they are not "regional entity policies."(9) Several very informal terms are used that should be replaced with more specific language, such as "walk down" (R5.2) and "local grid codes" (Attachment 1). In R6.2, the term "negligible transients" in too indefinite and should be replaced by a more objective measure. (10) The terms "unit," "plant," and "facility" are used inconsistently in the draft.(11) M4 refers to a "request" and a "response," but there is no request/response interchange in the associated Requirement R4.
Response: The SDT thanks you for your comment. **Regarding the first comment, in the current draft of the standard, all of the units that meet the Applicability section are required to have their models**		

Organization	Yes or No	Question 4 Comment
		verified within 11 years – 50% will be verified within seven years (six years to capture a voltage excursion, and then one year to finish the model verification). Also, the SDT believes, and the majority of industry responders when asked the question in the first posting agree, that the implementation plan provides proper balance between the need to verify excitation control system models and the fact that there are Generator Owners that currently do not have the expertise to perform model verification required. It may not be feasible to rely entirely on consultants to assist the industry with performing unit verification within a short timeframe such as a 5 year period; possibly leading to compliance violations by unfortunate Generator Owners. The 10 year implementation timeframe will provide the industry adequate time to verify the models and data for the excitation control systems and also develop expertise for performing these verifications. **Regarding the second comment, from the time it is decided that model verification is necessary, one year is allowed to capture the recording of the equipment response to an appropriate voltage excursion. One year is not an unreasonable amount of time to perform a staged test or to capture an ambient event. After the event is captured, only 180 days is provided for the completion of model verification.** **Regarding the third comment, the SDT believes that the periodicity of capturing events and subsequently finishing the verification including the documentation is not an activity directly related to the reliability of the BES. The Attachment has been re-worked for clarity in the current draft.** **Regarding the fourth and fifth comment, Attachment 1 has been re-worked for clarity in the current draft.** **Regarding the sixth comment, both the second and third bullets in Requirement 3 allow the Transmission Planner a process to address inaccurate models with the Generator Owner.** **Regarding the seventh comment, the SDT thanks you for catching this oversight and has made the correction.** **Regarding the eight comment, the SDT agrees.** **Regarding the ninth comment, the SDT removed the term "local grid codes". Regarding the other terms, the SDT feels that they are terms that are well understood by industry.** **Regarding the tenth comment, the SDT used the term "unit" for a single generating unit, the term "plant" for sites with multiple units, and "facility" when appropriate for either a single unit or a plant.** **Regarding the eleventh comment, the SDT thanks you for your observation and has modified M4 appropriately.**
RFC	Yes	RFC offers the following suggestions regarding the Violation Severity Levels:1. VSL for R1 - There is a disconnect between the date listed in the VSLs and requirement. The timeframe for the "Lower" VSL starts at 90 calendar days though the requirement states "within 30 calendar days". Where does an entity fall if they provide instructions 45 calendar days of receiving the request? Based on the current VSLs, they would not even fall under the "Lower" VSL.2. VSL for R3 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R3." Or conversely remove this language from the "Severe" VSL and replace with "R3".3. VSL for R4 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R4." Or conversely

Organization	Yes or No	Question 4 Comment
		remove this language from the "Severe" VSL and replace with "R4".4. VSL for R5 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R5." Or conversely remove this language from the "Severe" VSL and replace with "R5".5. VSLs for R6 - To be consistent with the language in the "Severe" VSL, add the following words to the end of the "Lower", "Moderate" and "High" VSLs: "...as specified in Requirement R6." Or conversely remove this language from the "Severe" VSL and replace with "R6".
Response: The SDT thanks you for your comment. Regarding your first comment, Requirement 1 has been corrected to specify 90 days instead of 30 days. This resolves the discrepancy between the Requirement and the Lower VSL. **Regarding your remaining comments, the language in the Severe VSL for R3, R4, R5, and R6 was revised to match the format of the other VSLs.**		
Consolidated Edison Co. of NY, Inc.	Yes	Requirement R5 - Please define the term "technically justified." We recommend using wording similar to Comment form paragraph 8) in that definition:"[S]upply technical justification that demonstrates either a) the unit affects a stability limit, or b) the simulated unit response does not match a measured unit response (most likely captured during a system disturbance event)."
Response: The SDT thanks you for your comment. Regarding the last comment, several comments expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review.		
PPL Electric Utilities	Yes	1. Each requirement can be accomplished by itself; but the 90 day vs 60 day vs 180 days on the various 12 requirements will likely create documentation confusion for communication and data retentions. Suggest that the draft be simplified to enhance coordination amongst requirements by applying a single time frame for completion of the requirements.2. Paras. R2 and R2.1.1 are not clearly worded. The present R2 text should end after the word "software;" and para. R2.1.1 should state that "Verification consists of developing one or more models that collectively include the following information:"The present R2.1.1 text, "acceptable to the Transmission Planner," is not included in this suggested revision to make it clear that the R2 Violation Severity Levels later in MOD-026-1 pertain to a GO's first submittal of a verified model, and the R3 Violation Severity Levels deal with failure to meet follow-up requirements if the

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		Transmission Planner finds the first submittal unacceptable. This distinction is particularly important given the compliance criteria ambiguity discussed in comment #3 below. If on the other hand it was intended that models achieve verified status only after being accepted by the Transmission Planner, the term "verified model(s)" in the R2 Violation Severity Levels should be replaced with, "initial submittal of proposed-verified model(s)". 3. There is presently no definition of the voltage excursion magnitude and intensity or the recording instrumentation sampling rate required for a valid verification event, nor are there any specifics regarding how closely the model must match the recorded response. The references in MOD-026 provide guidance but not necessarily NERC pass/fail criteria, especially since Transmission Planners may differ in their preferences. Perceived shortcomings in these respects would presumably trigger the Transmission Planner expression of concern described in para. R3, but it would be better to establish the rules up-front rather than addressing the matter only after a GO has attempted to comply with MOD-026.4. The definition of a "technically justified request" in para. R5 is unclear. Does this term apply only if a model fails to meet the requirements of R6.1-R6.3, or can there be other reasons? In the latter case the wording of the R5 Violation Severity Levels should be modified to start the clock only after agreement has been reached that a request is technically justified.5. The means by which a walk-down would lead to identification of model parameters in para. 5.2 is not understood.

Response: The SDT thanks you for your comment. (1) The SDT believes it is better for industry to have 180 days to perform model verification activities in lieu of establishing a universal 60 day period to perform all activities required just to achieve timeframe consistency among the Requirements.

(2) The SDT believes language is clear following removal of the word "collectively" from the paragraph. The SDT also points out that standard language proposed is for facilitating verification of the dynamic model, and not development of the dynamic model.

(3) The standard states "what is required" but not "how to accomplish what is required". The SDT considered ways to quantify a method for evaluating how well the equipment's measured response matches the model's predicted response. However, since a generally accepted technique or criteria for making this quantitative assessment does not exist, the SDT believes that the peer review process incorporated into the standard will ensure model quality. The SDT believes all entities involved with the peer review process have common purpose to develop an accurate excitation control system model. It should be noted that the standard is written so that the Generator Owner "owns' the model, and as such, even with the peer review process described, the Generator Owner has final say on the voltage excursion used, including sampling rate, for model verification as well as determining if the equipment recorded response satisfactorily matches the model's predicted response. The Generator Owner should not be concerned with "acceptance criteria" proposed by a transmission entity.

(4) The "technical justification" is not related to Requirements R6.1 – R6.3. These requirements only address if the model is useable by integrating successfully into the Transmission Planner's dynamic simulation software. Several comments expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated

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unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately. Keep in mind only units identified in the Registry Criteria and not included in the draft standard Applicability Section can be requested to have a model review. **(6) The "walk down" to correct model parameters could be as simple as identifying in the field that equipment gain or limit setting values are incorrectly represented in the model.**		
American Transmission Company	Yes	Please give consideration to the following suggestions:1. In Applicability, 4.2, Include the explanation that "average capacity factor is the average of all the unit or plant output values compared to the gross nameplate rating value" since some have asked how this value is defined and calculated.2. In Applicability, 4.2.4 - add "Transmission Planner" to this item because Transmission Planners may also have insight and the means to provide technical justification for the inclusion of specific units in their system.3. In Requirements, R1, bullet 1 - remove this bullet 1, or combine it with bullet 2, because it appears to be redundant with bullet 2, rather than distinctly different.4. In Requirements, R2.1.4 - replace "model structure and data" with "block diagram and model parameters" for more clarity.5. In Requirements, R2.1.6 - replace "model structure and data" with "manufacturer, model number, block diagram, and model parameters" for more clarity and specificity.6. In Requirements, R2.1.6 - add "and indicate whether the power system stabilizer is planned to be in-service and out-of-service in the planning horizon."7. In Requirements, R4 - revise the text from "within 180 days of making changes" to "within 180 prior to making changes" for more clarity.
Response: The SDT thanks you for your comment. The responses below are numbered to match the comments. **1. To clarify concerns regarding calculating unit capacity factor, the SDT has incorporated into the standard the capacity factor calculation specified in Appendix F of the GADS Data Reporting Instructions (which can be obtained from the NERC website).** **2. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.**		

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3. Regarding bullets 1 and 2 in Requirement R1, the information described in each bullet is distinctly different. The first bullet "Instructions on how to obtain the list of acceptable excitation control system and plant volt/var control function model for use in dynamic simulation" is literally just a list of acceptable model types. For many entities, especially those which utilize dynamic simulation software that is widely utilized, this is all the information that they will require. The second bullet, " Instructions on how to obtain the Transmission Planner's software manufacturer's dynamic excitation control system and plant volt/var control function system model library block diagrams and/or data sheets", pertains to the actual block diagrams and/or data sheets (as opposed to only a "list" of model types in bullet 1). The information in the second bullet will likely be required by entities that do not use dynamic simulation software that is widely utilized. **4. The SDT intends to keep the phrase "Model Structure" since a model structure is a block diagram without parameter values.** **5. The language of R2.1.4 has been revised to align with the style of R2.1.6.** **6. Regarding R2.1.6, the SDT does not believe it is appropriate to communicate PSS status as part of a modeling standard.** **7. The SDT believes that the intent of Requirement R4 is captured with the current language. The standard does not address notification regarding equipment changes, nor does it address the transmittal of preliminary model data from the equipment manufacturer; it addresses a requirement for the verification of the model for the "changed out" equipment. The models for the new equipment cannot be verified until the equipment is installed and available.**		
Indiana Municipal Power Agency	Yes	IMPA appreciates the efforts of the SDT on getting the applicability section correct for the plants or units that truly impact the stability response of the BES. However, the standard does contain a loop-hole to the SDT's intent. On page 3 of 16, footnote 4 to the applicabilty section (4.2.4)states: "a technical justification for verifying each of those units or plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit, or evidence that the simulated unit or plant response does not match measured unit or plant response". The first or word in that sentence should be replace with the word "and". A technical justification for verifying each of those units and plant(s) that demonstrates through simulation and/or measured response that the unit or plant affects a stability limit should both be required. By requiring both of these items, it might prevent units the size of 1MW from having to perform this standard.In addition, who qualifies what is a technically justified unit or what is a technical justification? Past history as shown that technicaly justifications have been used "losely" by different regions and entities. The Generator Owner should have some means of appealing this request by the Planning Coordinator.
Response: The SDT thanks you for your comment. Several commenters expressed concern with the new Requirement added to the standard giving the Planning Coordinator authority to require model review for a unit not specified in the standard Applicability section. The SDT added this language to the draft standard after considering industry comments to the first posting noting that the Applicability section is a subset of the Compliance Registry criteria. Based on the latest round of industry feedback, the SDT now proposes Applicability Section language allowing the Planning		

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Coordinator to request additional model information (possibly model verification) only if technical justification demonstrates the simulated unit response does not match the measured unit response. Original technical justification language for units that affect a stability limit has been removed from the standard. To emphasize for understanding, the SDT points out only units that meet or exceed the Registry Criteria unit MVA thresholds (> 20 MVA) are subject to Requirement R5. This observation should allay concern the Requirement could be misused inappropriately.		

END OF REPORT